

REAL RESOURCES INC

ANNUAL REPORT 2004

WHAT HAVE WE DONE FOR YOU LATELY?



REAL RESOURCES INC. (REAL) IS A CALGARY-BASED OIL AND GAS COMPANY ACTIVE IN THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS IN WESTERN CANADA. THE COMPANY HAS ACHIEVED DYNAMIC GROWTH THROUGH EXPLORATION, DEVELOPMENT AND STRATEGIC ACQUISITIONS. REAL TRADES ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL RER.

HIGHLIGHTS

(\$ thousands, except where noted)	2004	2003**	% change
FINANCIAL			
Production revenue	108,103	73,282	48
Cash flow from operations*	56,173	36,142	55
Per share (basic)*	\$ 2.09	\$ 1.58	32
Per share (diluted)*	\$ 2.03	\$ 1.56	30
Net earnings	16,155	14,597	11
Per share (basic)	\$ 0.60	\$ 0.64	(6)
Per share (diluted)	\$ 0.58	\$ 0.63	(8)
Net debt	58,498	67,697	(14)
Total assets	279,656	211,967	32
Shareholders' equity	143,994	89,580	61
Net capital expenditures	90,311	59,499	52
Average common shares outstanding (thousands)	26,932	22,804	18
OPERATING			
Working interest production			
Crude oil and liquids (bbls/d)	3,293	3,352	(2)
Natural gas (mcf/d)	24,478	12,833	91
Total oil equivalent (boe/d)	7,373	5,491	34
Average prices			
Crude oil and liquids (\$/bbl)	41.45	35.91	15
Natural gas (\$/mcf)	6.41	6.13	5
Cash flow netback			
(before abandonment)* (\$/boe)	20.90	18.12	15
Operating costs (\$/boe)	7.42	7.52	(1)
General and administrative costs (\$/boe)	1.41	1.59	(11)
Wells drilled			
Gross	112	91	23
Net	86.1	78.1	10

* Cash flow from operations, cash flow from operations per share and corporate netbacks are non-GAAP terms that represent net earnings adjusted for non-cash items on a boe and per share basis. The Company evaluates its performance based on these measures. The Company considers cash flow a key measure as it demonstrates the Company's ability to generate cash flow necessary to fund future growth through capital investment and to repay debt. The Company considers corporate netbacks a key measure as it demonstrates profitability relative to current commodity prices.

** Certain of the comparative amounts in the above table and following Management's Discussion and Analysis and Consolidated Financial Statements have been restated to conform with the new accounting guidelines issued by the Canadian Institute of Chartered Accountants that became effective on January 1, 2004 and required retroactive application and reclassification. These guidelines relate to the determination of the Company's asset retirement obligation, the adoption of the fair-value based method of calculating the value of stock-based compensation and the reclassification of transportation costs (see note 3 to the Consolidated Financial Statements).

HOW DID WE PERFORM IN 2004?

EXPLORATION SUCCESS

- Pursued organic growth through the drill bit
- Strong technical team, committed to 3-D seismic
- Drilled 112 gross wells with 87 percent success rate
- Reduced cycle times to drill, complete and tie-in new wells
- Discovered 31 new pools
- Added 6.2 million boe in proved plus probable reserves

PRODUCTION GROWTH

- Averaged production of 7,400 boe per day, up 34 percent year-over-year
- Exited 2004 at 8,600 boe per day
- Production was 55 percent natural gas-weighted
- Capital expenditures were \$90 million
- Year-end 2004 proved plus probable reserve-life-index (RLI) of 9.5 years

FINANCIAL SUCCESS

- Breakthrough year in production, reserves, market recognition
- Cash flow \$56 million (\$2.09 per share)
- Average netbacks of \$24.89 per boe
- Average F&D proved plus probable costs of \$14.48 per boe
- Year-end debt to cash flow 1:1
- Year-end share price of \$11.84

OPPORTUNITY DEVELOPMENT

- Broad prospect inventory, including high-impact exploration
- Seismic database: 6,000 miles 2-D, 370 square miles 3-D
- 307,000 net acres of undeveloped land
- Drilling inventory : 600+ wells
- \$145 million 2005 capital budget
- 140 gross wells in 2005



WHAT HAVE WE DONE FOR YOU LATELY?



We delivered on our key growth targets of production and cash flow. Our technical team delivered excellent results, including an **87** percent drilling success rate and 31 oil or natural gas discoveries. Volumes grew at four out of Real's five core areas, with **100** percent of growth delivered through the drill bit. Central Alberta experienced strong drilling results and volume growth, maturing into a new core area. The markets recognized Real's performance, driving significant share price appreciation in 2004.



Production
(boe/d) (6:1)



Production Per Share (bbl per mm shares)

WE MET OUR KEY GROWTH TARGETS



Cash Flow per Share (\$ per basic share)



Year-End Closing Share Price (\$)

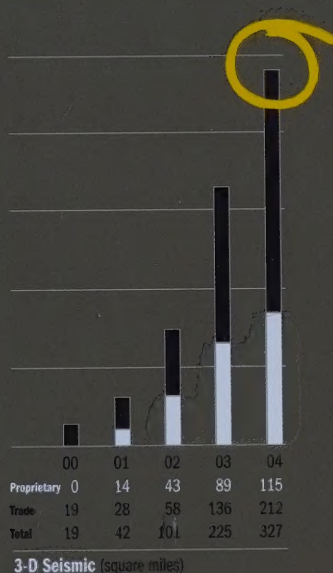
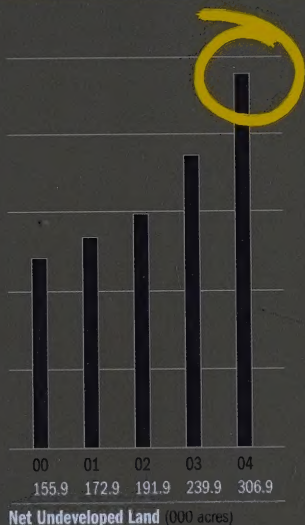


WHAT CAN YOU LOOK FORWARD TO?

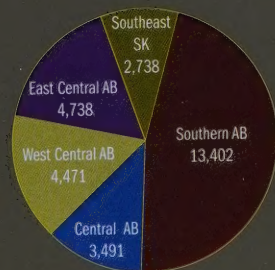


In short: continued growth in volumes through the drill bit. Real's **\$145** million 2005 capital budget will fund 140 gross wells – the Company's largest drilling program ever. The target average production rate of **10,000** boe per day represents volume growth of 35 percent year-over-year. Production is forecast to grow in four out of five core areas.

In keeping with Real's evolution, the program includes a larger number of deeper, high-impact exploratory wells in higher-reward prospect areas. To build longer-term success, Real's land acquisition and seismic programs will ramp up to record levels. Real will continue to exercise financial discipline, including maintaining a responsible debt-to-cash-flow ratio.



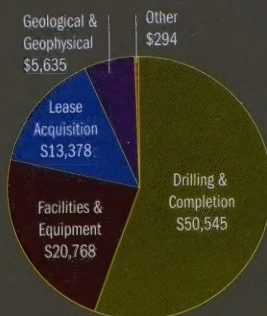
WE WILL DELIVER REAL VALUE IN 2005



Total Reserves: 28,840 mboe

Year-End Reserves By Area (mboe)

(total proved and probable reserves)



2004 Total Capital: \$90 million

2004 Capital By Activity (\$000s)

MESSAGE TO OUR SHAREHOLDERS

Q&A

LET'S START WITH THE BIG PICTURE – WHAT WAS REAL TRYING TO DO IN 2004 AND HOW DID THE RESULTS COMPARE TO THE PLANS?



For Real, 2004 was a breakthrough year in terms of production and cash flow plus market recognition. Our biggest goal was to enhance the market's confidence, and the best way to do that was to put good numbers on the board. That happened in 2004. Our share price went from \$5.50 to \$11.84.

WHAT WERE THE METRICS THAT MATTERED, AND HOW DO THOSE RESULTS BENEFIT SHAREHOLDERS AND POSITION REAL FOR FUTURE GROWTH?



The things that we told the street we would do, we did, and we exceeded them: production, cash flow and earnings. The positive consequences of our exploration success and depth of drilling inventory continues. The success generated by the drill bit in 2003 drove our results in 2004, and what was discovered in 2004 will drive 2005.

LEFT TO RIGHT:



✓
Frank P. Muller
Pamela J. Orr
Ken P. Murphy
Lowell E. Jackson

HOW DO YOU COMPARE REAL'S OPERATING APPROACH TO THAT OF OTHER CANADIAN ENERGY PRODUCERS?



We made a decision to grow organically, through the drill bit, rather than through acquisitions. We have a strong emphasis on exploration, supported by a major commitment to 3-D seismic. Many of the companies in the past that grew to substantial size took a long time to do it. It just didn't happen in five years. That's our strategy. We're an old-time oil and natural gas company. We take the time that's needed. Today, more and more people are accepting the validity of building Real organically towards 20,000 boe per day – that's a very telling shift in attitude.

MESSAGE TO OUR SHAREHOLDERS

WHY ARE YOU NOT MAKING ACQUISITIONS?



This question is very common. Early on we made five selective acquisitions for specific purposes – to gain initial production, to obtain a TSX listing, to create new prospects and so on. Oil prices were much lower at that time. Today we would make an acquisition not because of need or to backfill a failure, but only if the opportunity was just right for us. We've looked at lots of frogs in the past year – but we haven't found any princes. We're diligent in looking at things, and we compare them to what we've generated in-house. If they don't compare favourably, why do it?

HOW DOES A SMALL COMPANY COMPETE TECHNICALLY WITH THE BIG PLAYERS?



Real has built and retained a top-notch technical team, including people with big-company experience. Part of this is our outlook: we love to generate prospects, and we love to drill wells. The growth of the trust sector means there are fewer and fewer real exploration-oriented companies out there, and this has had a positive effect on the sorts of experienced, high-quality people who are available to smaller exploration companies. In addition, we're very focused on seismic, especially 3-D seismic, and this helps us create as detailed a technical picture as one would have found at a much larger company historically.

WERE THERE IMPORTANT DEVELOPMENTS ON THE FINANCE SIDE IN 2004?



We continued to exercise financial discipline in what we do and how we do it. In the spring we raised \$27 million in common equity at \$6.35 per share, and at year-end we raised \$20 million in flow-through shares at \$15.75 per share. The purpose was straightforward: the funds were needed to invest in our exploration and development program. We had results to show for it. Our equity issues were not dilutive – they were accretive.

MESSAGE TO OUR SHAREHOLDERS

WHAT ARE YOUR MAJOR PLANS FOR 2005?



Our \$145 million capital budget will fund 140 gross wells, about two-thirds of which will be natural gas-focused. This year's planned drilling activity is not only our largest number of wells ever, it's our largest number in the deeper part of the basin. This is exciting. The impact of successful drilling could be much greater than anything we've done in the past. In addition, we continue to have a large inventory of lower-risk prospects, including about 400 shallow gas locations that can be drilled whenever they're needed. In sum, we have a lot of flexibility.

ARE YOU PROVIDING ANY GUIDANCE FOR REAL'S PERFORMANCE METRICS IN 2005?



We are targeting average production of 10,000 boe per day in 2005. At our assumed commodity prices of US\$35.00 per bbl WTI, \$0.84 foreign exchange rate and \$6.00 per mcf AECO, we should generate cash flow in the range of \$60 million.

WHO DROVE REAL'S SUCCESS IN 2004?



I'm very proud of and pleased by the people we have at Real – who they are and what they do. I'm also cognizant that our "customer" is the shareholder. I'd like to give thanks to those patient shareholders who are looking for reliable and steady performance, and who give us the time to grow through the drill bit.



Lowell E. Jackson, P. Eng.
President & Chief Executive Officer
March 16, 2005

OPERATIONS REVIEW



HOW DID OUR EXPLORATION TEAM PERFORM IN 2004?

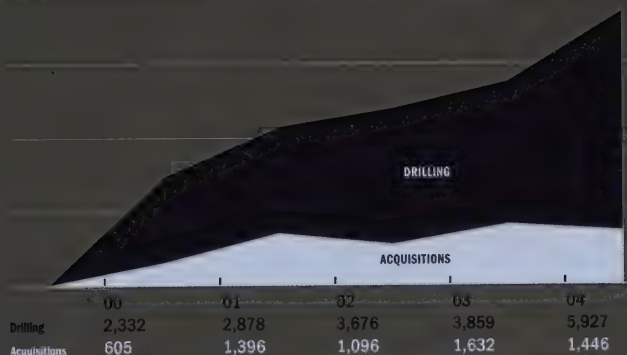
The mandate of Real's technical team is organic growth through the drill bit. We are a technically focused group with a strong emphasis on geology and seismic. A key principle is "every good drilling idea will be acted on."

Understanding the effectiveness of seismic, Real has assembled a database of 6,000 miles of 2-D and 327 square miles of 3-D seismic.

In 2004 Real's technical team was active in all five core areas, drilling **112** gross wells at high working interests, including 36 gross exploration wells, and achieving a drilling success rate of 87 percent.

Real's technical team plans to drill **140** gross wells in 2005, including eight high-impact exploratory tests.



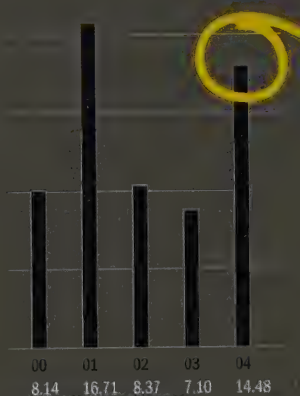


Production Growth (average daily boe)

WE BUILT REAL VALUE THROUGH THE DRILL BIT



Proved + Probable Reserves
(mmboe) (6:1)



Finding and On-Stream Costs
(Proved + Probable Reserves)
(\$ per boe) (6:1)
including acquisitions and revisions



HOW DO WE RATE OUR ASSETS?

Real's five core areas contained the opportunities needed to drive the Company's average production from 5,491 boe per day in 2003 to

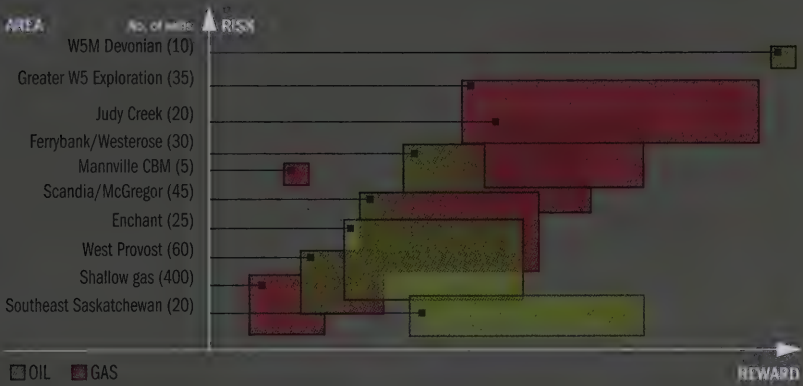
7,373 boe per day in 2004. Real's property mix creates a stable production base plus a range of opportunities including low-risk infill oil drilling, resource play-type gas development, conventional gas exploration and high-impact grassroots exploration. Real's diversified, balanced asset base means the Company's destiny is not tied to any single property.

Our year-end proved plus probable reserve life index was 9.5 years.

The asset base includes **307,000** net acres of undeveloped land at high working interests. Our drilling inventory totals more than 600 locations providing 2-3 years' worth of accelerating, growth-oriented activity. In 2005 Real will be active in all five core areas, targeting average production of 10,000 boe per day.

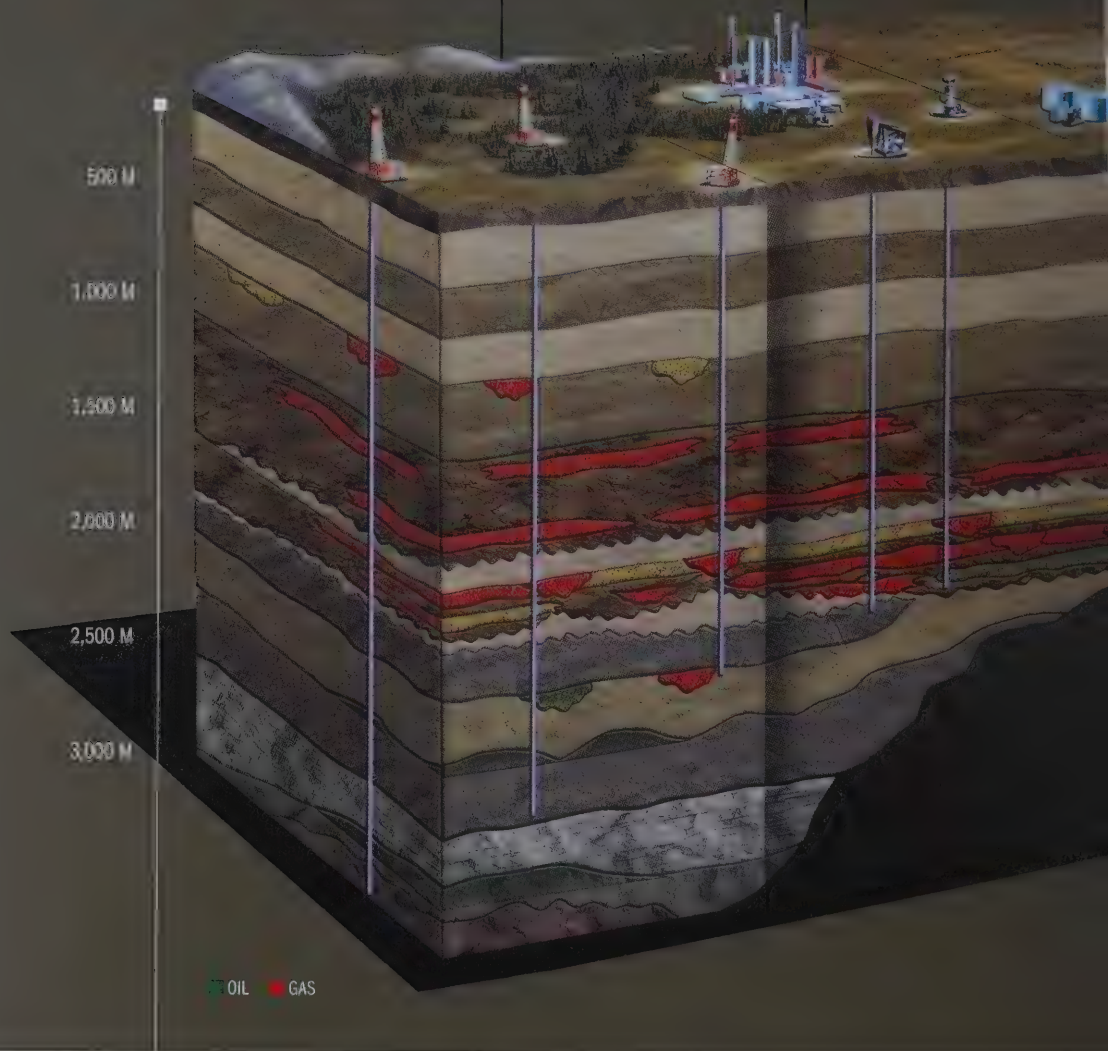
Core Area	Land Holdings (gross acres)	Net Production (boe/d)	Netbacks (\$/boe)	Reserves Proved plus Probable (mmboe)
Southeast SK	12,309	562	31.40	2,738
East Central AB	118,801	1,534	23.74	4,738
Southern AB	162,036	3,622	23.40	13,402
Central AB	23,194	875	27.72	3,491
West Central AB	212,596	780	26.19	4,471

Inventory of Drilling Locations



Undeveloped Land Holdings



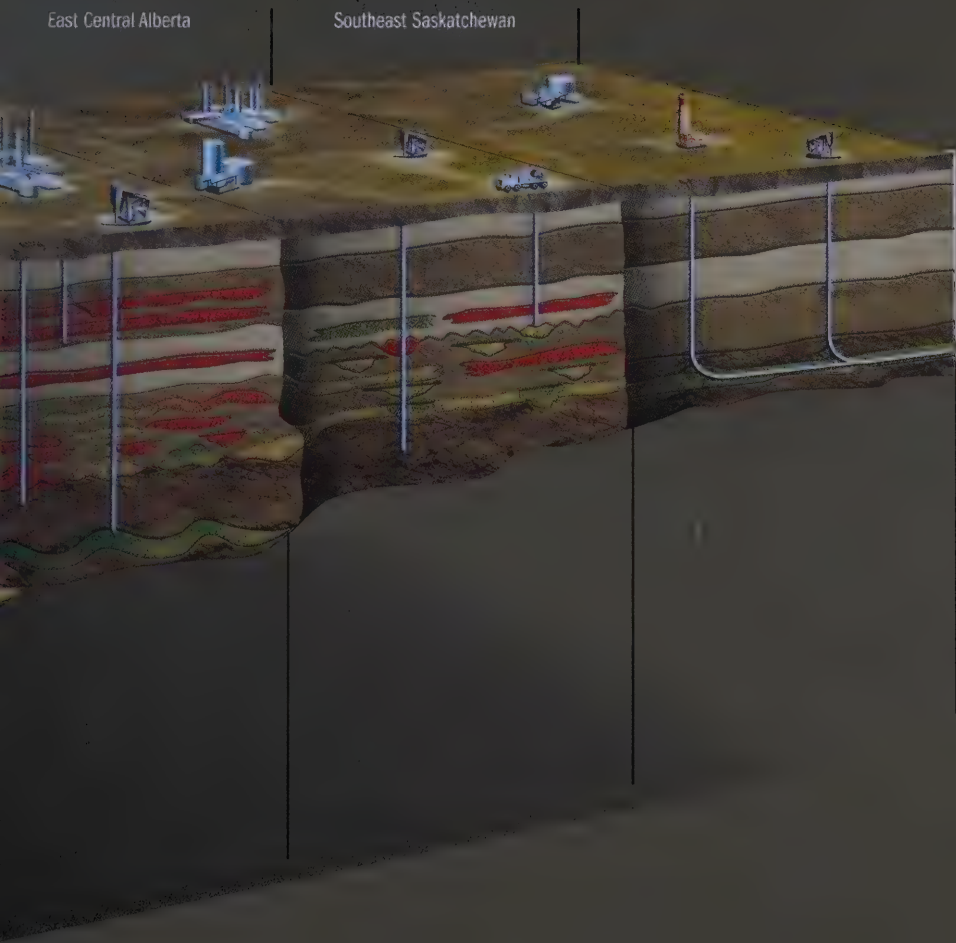


CORE EXPLORATION AND DEVELOPMENT REGIONS

West Central Alberta This core area is assuming increased importance as Real continues to grow. West Central Alberta offers highly productive, longer-life natural gas and crude oil targets from numerous zones. With 20 wells drilled in 2004, Real's production grew to 780 boe per day. In 2005 Real is committing \$35 million to drill 25 gross wells, targeting average production of 2,100 boe per day.

Central Alberta This rapidly emerging core area yielded numerous discoveries in 2004, generating average volumes of 875 boe per day. The medium-depth natural gas, condensate and oil targets found in this competitive region offer high well-productivity and strong cash flow. With four producing properties and 36 sections of land, Real plans 25 wells in 2005, targeting average production of approximately 1,200 boe per day.

East Central Alberta Real's land holdings are yielding down-spacing opportunities. Viking gas and oil accumulation offers a long-life, low-decline asset. Real drilled 12 wells in 2004 with success. A further 20 wells are planned in 2005. With East Central Alberta in harvest mode, production is expected to decline from 1,533 boe per day in 2004 to 1,200 boe per day in 2005.



's extensive
x, low-cost
regional
The Viking
source play.
100 percent
planned
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Southern Alberta This area's four main properties produce conventional natural gas from 11 zones discovered to date, crude oil from the Arcs Formation and long-life natural gas from resource play-type shallow formations. Average 2004 production of 3,621 boe per day represented more than 40 percent of Real's volumes. Following major growth in 2004, Real plans to drill 45 wells in 2005, targeting average production of 4,500 boe per day.

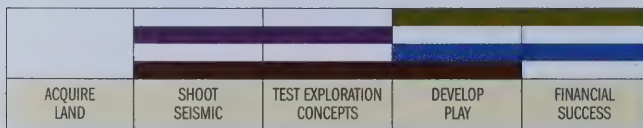
Southeast Saskatchewan Real's original core area has yielded new opportunities for horizontal infill drilling. Horizontal wells offer excellent return on capital, and the region's tight oil generates high netbacks. After several years of production decline in Southeast Saskatchewan, Real exited 2004 with growing volumes. The Company has 10 wells planned for 2005, and is targeting production growth from 562 boe per day in 2004 to a 2005 average of 1,000 boe per day.

SOUTHEAST SASKATCHEWAN

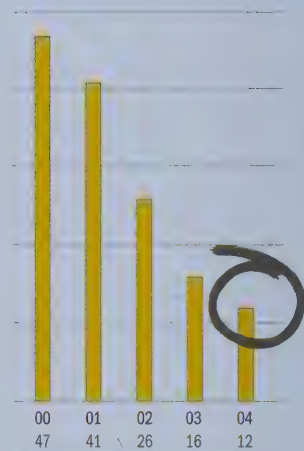
Following a deliberate drilling hiatus of several years in its original core area, Real in 2004 conducted a highly successful horizontal drilling program. Production, which had declined to 195 boe per day going into 2004, grew to 900 boe per day by year-end and exceeded 1,000 boe per day in early 2005. Real's four Southeast Saskatchewan properties generate high netbacks, thanks to the high-quality light oil, and low operating costs.

Common to Real's Southeast Saskatchewan properties is the importance of 3-D seismic. The land situation is competitive but Crown lands and freehold parcels do become available. Pools of up to several million barrels in reserves can be found in parcels as small as a half-section. Real operates water disposal wells and owns key surface facilities, tied in by pipeline. Tie-in of new wells can be done in one week. Horizontal infill wells can reach pay-out in 45 days.

Stages of Prospect Development



- **Alida West** Recent regulatory changes authorized horizontal infill drilling down to 75 metres lateral spacing. As a result, four new horizontal infill wells were drilled in 2004. Following initial flush production as high as 250 bbls per day, these horizontal wells typically stabilize at 40 bbls per day, maintaining such rates for up to 10 years. Real plans to drill three additional horizontal infill wells in 2005.
- **Alida-Cantal** Success at Alida West triggered similar downspacing opportunities at Alida-Cantal. Typical for Southeast Saskatchewan, this property covers a small land area but contains potentially large oil reserves. As a result of a new proprietary 3-D seismic program, Real plans 4-6 new horizontal infill wells in 2005.
- **Ashley Lake** This smaller, non-operated property, also has potential for horizontal infill drilling. Real is in discussion with the operator to initiate a four-well program in 2005.
- **Rocanville** This property historically yielded stable, long-life oil production from vertical Bakken wells. Real plans one new well in the first half of 2005 and will shoot new 3-D seismic to develop further drilling locations.



Land Holdings
(000 gross acres)



Net Production
(average daily boe) Q1 05e = 1,150 boe/d

EAST CENTRAL ALBERTA

In East Central Alberta, Real has a mix of long-life, resource play-type oil and natural gas from low-rate wells tapping the regional Viking sands. This core area also has longer-term potential for Mannville Formation coalbed methane, an important emerging play in Western Canada. In 2004, East Central Alberta averaged 1,155 bbls per day of crude oil and 2.25 mmcf per day of natural gas.

Stages of Prospect Development

ACQUIRE LAND	SHOOT SEISMIC	TEST EXPLORATION CONCEPTS	DEVELOP PLAY	FINANCIAL SUCCESS

■ West Provost Real's 175-section land base was accumulated through a mix of acquisitions and land purchases. Real in 2004 focused on the extensive potential in the area's ubiquitous Viking sands. Real has less than one well per section on gas-bearing lands and only four wells per oil-producing section. Current practice permits downspacing to three natural gas wells or eight oil wells per section. This creates a strong well inventory to exploit this long-life, low-decline resource play.

Real's 2004 program resulted in eight down spaced oil wells and four "first well on the section" natural gas wells. All 12 wells were brought on-production quickly through Company owned and operated facilities. The oil wells came on at 25 bbls per day and should stabilize at 15 bbls per day. The gas wells came on at 200 mcf per day and should stabilize at 125 mcf per day. These Viking wells have an estimated economic life of up to 30 years. The Company also re-completed 10 older wells, gaining a two- to three-fold increase in productivity.

Real is pleased with this harvest-style program, which demonstrates the ability to find new reserves and deliverability in a region producing for 40 years. Operations are made cost effective through multiple drilling and subsequent completion activities. The Company plans to drill 20 down spaced wells in 2005.

■ Coalbed methane (CBM) The Company's lands have extensive Mannville coal seams, and Real is taking steps to participate in this emerging play. In 2004 Real farmed out one CBM exploration well to a knowledgeable U.S. Independent. This successful well will be followed by a four well pilot-scale drilling program in 2005.



Land Holdings
(000 gross acres)

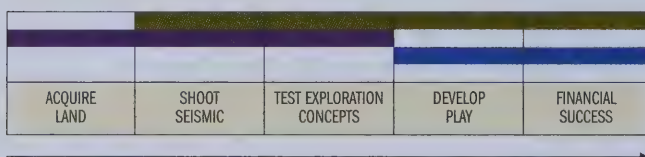


Net Production
(average daily boe)

SOUTHERN ALBERTA

Real's 56-well drilling program in Southern Alberta represented half of the Company's activity in 2004. Real focused on natural gas exploitation and its Arcs oil program. Forty percent of the wells were exploratory. Southern Alberta volumes grew by almost 50 percent in 2004, to an average of 3,621 boe per day, of which 68 percent was natural gas production.

Stages of Prospect Development

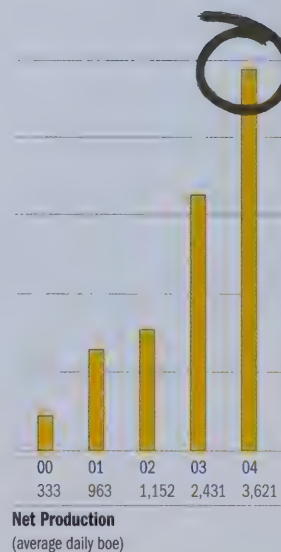
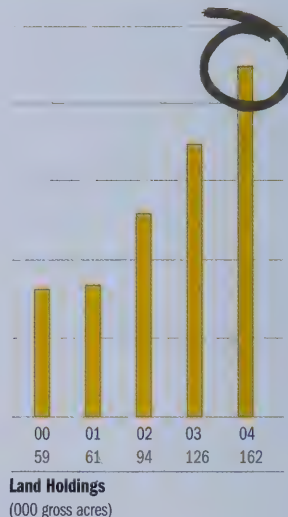


- **Scandia/Enchant** This important property, comprised of 80 sections of land, offers multi-zone gas opportunities plus one main oil zone, the Arcs. Major gas reserves discovered in 2003 were tied in during 2004, bringing production to 2,157 boe per day. To date Real has found natural gas in 11 zones through a combination of geology and seismic.

The Company's natural gas is processed at three third-party facilities. The Company's goal is to maintain volumes going forward, with 24 wells planned through 2005.

The Arcs oil program met with strong success in 2004, including a significant discovery developed with six wells. To date, 30 of Real's 35 Devonian Arcs wells have been successful, with 3-D seismic a key tool. Real's Arcs oil production totalled 1,150 bbls per day at year-end 2004.

- **McGregor** Starting with two sections in late 2003, Real now controls 31 sections of land with low drilling density but showing all the signs of a successful gas-producing area. In 2004 Real drilled four exploration wells resulting in three natural gas discoveries. The wells were on production at restricted rates by the end of February 2005. Five further wells are planned by the end of Q1. Real has ensured access to processing capacity by constructing pipelines to three third-party operated facilities.
- **Shallow Gas Atlee-Buffalo**, Real's 48-section contiguous block, has 107 low-rate Medicine Hat/Milk River wells on production, generating combined volumes of 2 mmcf per day. With only three producing wells per section, Real foresees downspacing to eight wells per section, creating a very low-risk, 240-plus-well shallow gas development inventory. Also in 2004, a 31-section purchase at Bindloss created the opportunity to develop a 125-well shallow gas project.



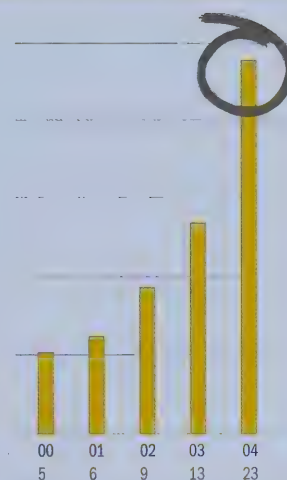
CENTRAL ALBERTA

An emerging play in 2003, Real's Central Area properties blossomed into a new core area in 2004. In only two years the Company's interests have grown from a one-section farm-in to four producing properties covering 36 sections. Real has now drilled 25 wells at high success rates, growing production to approximately 1,100 boe per day at year-end 2004, with a further 400 boe per day behind pipe. This success was accomplished in a highly competitive area.

The Central Alberta area's primary target is natural gas containing condensate in zones up to 1,900 metres deep. Real has also discovered a new oil pool. Historically dominated by major producers, the area offers excellent infrastructure for third-party processing arrangements. The Company plans to drill approximately six wells per quarter through 2005, with activity on each prospect.

Stages of Prospect Development

				ACQUIRE LAND
				SHOOT SEISMIC
				TEST EXPLORATION CONCEPTS
				DEVELOP PLAY
				FINANCIAL SUCCESS



Land Holdings
(000 gross acres)

- **Ferrybank East** This growing property produces sweet, light Ellerslie oil from wells drilled in 2004. These wells had been on restricted rate, but late in 2004 received good production practice. In 2005 Real plans to downspace the Ellerslie oil pool. The Company also proved up a new gas resource play-type.
- **Ferrybank West** In 2004 Real drilled four discoveries. Ferrybank West produces natural gas from the Glauconitic and Ellerslie formations and oil from the Ostracod. Volumes totalled 260 boe per day at year-end 2004.
- **Crystal** At Crystal, by late 2004 Real captured 11 sections of land through Crown purchases and farm-in. Four wells drilled in 2004 resulted in natural gas discoveries. All were tied into a third-party processor and brought on-production by late-2004. Real plans to downspace all four discoveries in 2005.
- **Westerose** This property has three producing natural gas and oil wells that averaged a combined 300 boe per day in 2004.



Net Production
(average daily boe)

WEST CENTRAL ALBERTA

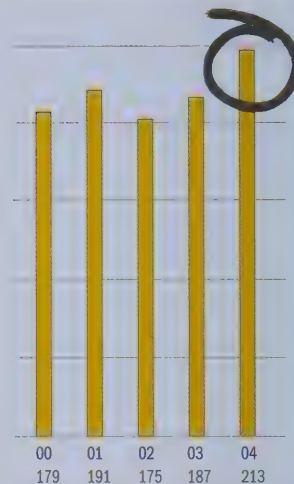
The extensive opportunities in West Central Alberta occupy the high-reward, higher-risk end of Real's five core areas. This area offers multi-zone medium-depth and deep natural gas and oil opportunities on seismically and geologically defined prospects. Persistence is required to achieve lasting success.

To date Real has assembled a land position of 330 gross sections, acquired largely through Crown sales and small farm-ins. Real commenced a major 3-D seismic program in 2004. Real drilled 20 gross wells in West Central Alberta in 2004, of which 35 percent were classified as exploratory, with the balance of development wells having an exploration component. In 2005 Real is committing increased capital for drilling, land and seismic to this high-impact region.

Stages of Prospect Development

ACQUIRE LAND	SHOOT SEISMIC	TEST EXPLORATION CONCEPTS	DEVELOP PLAY	FINANCIAL SUCCESS

- **Judy Creek** In 2004 Real drilled five wells, discovering four new natural gas pools. The property has multi-zone targets at depths to 1,800 metres. The Company holds 24 sections and has farmed in on a further 23 sections. Wells at Judy Creek typically flow at 500 mcf per day, yielding reserves of 1 bcf per well. Real is anticipating to build Judy Creek into a solid property.
- **Sturgeon Lake** Real also had a good result at Sturgeon Lake drilling a discovery well. It is now producing at 3 mmcf per day.
- **Stump** This prospect, launched three years ago, yielded a Real-generated Montney gas pool extension in 2004.
- **Deep Devonian Exploration** Real's high-risk, high-reward program of deep Devonian tests continued in 2004. Of ten prospects identified to date, three were drilled in 2004. All were cased for oil and gas and are under evaluation.

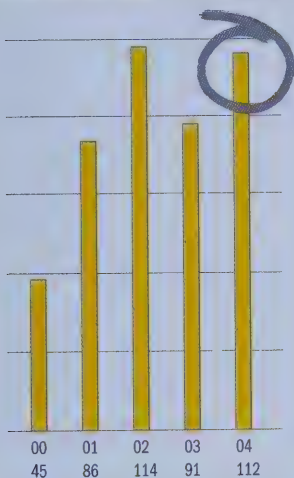
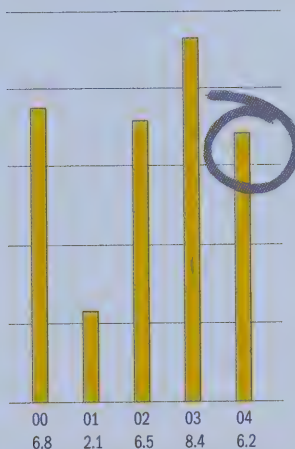


Land Holdings
(000 gross acres)

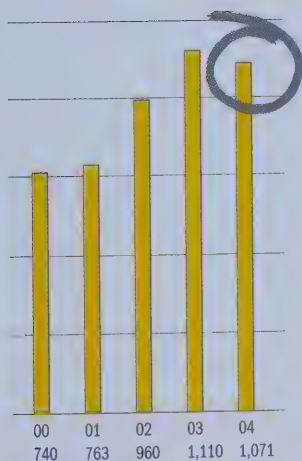
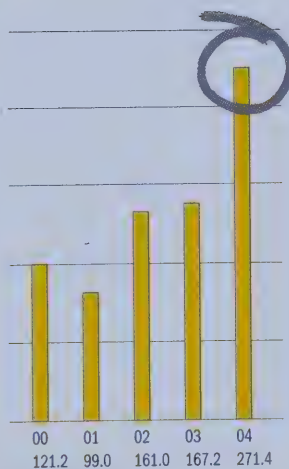


Net Production
(average daily boe)

OPERATIONS AND STATISTICAL REVIEW

**Drilling Activity** (gross number of wells drilled)**Proved + Probable Reserve Additions**
(mmboe) (6:1) including acquisitions and revisions

RESULTS OF REAL ORGANIC GROWTH IN 2004

**Reserves per Share** (proved plus probable)
(boe per thousand shares - basic)**Present Value of Future Cash Flow**
(proved plus probable) (\$ millions discounted at 15%)

Reserves Reconciliation ⁽¹⁾⁽²⁾ – Forecast Prices and Costs

Reconciliation of Company Gross Reserves by Principal Product Type

	Light and Medium Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Total (mboe)
Total proved				
Opening balance	8,212	60,200	575	18,820
Drilling	2,005	21,576	274	5,875
Revisions	(372)	(3,096)	(37)	(925)
Acquisitions	–	–	–	–
Dispositions	(11)	(181)	–	(41)
Production	(1,089)	(8,959)	(116)	(2,699)
Closing balance	8,745	69,540	696	21,031
Probable				
Opening balance	2,525	22,398	225	6,483
Drilling	1,777	8,548	98	3,300
Revisions	(411)	(8,983)	(57)	(1,965)
Acquisitions	–	–	–	–
Dispositions	(1)	(30)	–	(6)
Production	–	–	–	–
Closing balance	3,890	21,933	266	7,812
Proved plus probable				
Opening balance	10,737	82,598	800	25,303
Drilling	3,782	30,124	372	9,175
Revisions	(783)	(12,079)	(94)	(2,890)
Acquisitions	–	–	–	–
Dispositions	(12)	(211)	–	(47)
Production	(1,089)	(8,959)	(116)	(2,699)
Closing balance	12,635	91,473	962	28,843

(1) May not add due to rounding.

(2) Gross reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

Reserves by Property ⁽¹⁾⁽²⁾

<i>(at December 31, 2004)</i>	<i>Light and Medium Crude Oil (mbbls)</i>	<i>Natural Gas (mmcf)</i>	<i>Natural Gas Liquids (mbbls)</i>	<i>Total (mboe)</i>
Total proved				
Hays/Enchant	2,798	2,071	104	3,247
Scandia	286	12,253	157	2,485
Atlee-Buffalo	—	12,821	—	2,137
Ferrybank	459	6,807	73	1,667
West Provost	215	7,873	20	1,547
Alida West	1,092	604	—	1,193
Judy Creek	602	2,399	46	1,048
Pageant	37	4,812	15	854
Rocanville	751	—	—	751
Consort	680	188	1	712
Sounding Lake	674	119	6	700
Crystal	—	3,361	87	647
Neutral Hills	544	492	—	626
Majorville	—	3,555	1	594
Westerose	—	1,486	98	345
Other properties	607	10,699	88	2,478
Total	8,745	69,540	696	21,031
Probable				
Hays/Enchant	1,379	717	39	1,537
Scandia	194	3,421	39	803
Atlee-Buffalo	—	3,256	—	543
Ferrybank	95	3,153	31	652
West Provost	43	2,101	5	398
Alida West	392	247	—	433
Judy Creek	869	2,125	51	1,274
Pageant	10	1,201	4	214
Rocanville	122	—	—	122
Consort	161	36	—	167
Sounding Lake	231	41	2	240
Crystal	—	571	15	110
Neutral Hills	147	58	—	157
Majorville	—	448	—	75
Westerose	—	318	18	71
Other properties	247	4,240	62	1,016
Total	3,890	21,933	266	7,812

(1) May not add due to rounding.

(2) Gross reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

<i>(at December 31, 2004)</i>	<i>Medium Crude Oil (mbbls)</i>	<i>Light and Natural Gas (mmcf)</i>	<i>Natural Gas Liquids (mbbls)</i>	<i>Total (mboe)</i>
Proved plus probable				
Hays/Enchant	4,177	2,788	143	4,784
Scandia	480	15,674	196	3,288
Atlee-Buffalo	—	16,077	—	2,680
Ferrybank	554	9,960	104	2,319
West Provost	258	9,974	25	1,945
Alida West	1,484	851	—	1,626
Judy Creek	1,471	4,524	97	2,322
Pageant	47	6,013	19	1,068
Rocanville	873	—	—	873
Consort	841	224	1	879
Sounding Lake	905	160	8	940
Crystal	—	3,932	102	757
Neutral Hills	691	550	—	783
Majorville	—	4,003	1	669
Westerose	—	1,804	116	416
Other properties	854	14,939	150	3,494
Total	12,635	91,473	962	28,843

(1) May not add due to rounding.

(2) Gross reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

Summary of Oil and Gas Reserves – Forecast Prices and Costs ⁽¹⁾⁽²⁾

	<i>Light and Medium Crude Oil (mbbls)</i>	<i>Natural Gas (mmcf)</i>	<i>Natural Gas Liquids (mbbls)</i>	<i>2004 Total (mboe)</i>	<i>2003 Total (mboe)</i>
Proved					
Developed producing	7,664	54,759	596	17,387	13,763
Developed non-producing	183	5,809	71	1,222	2,544
Undeveloped	898	8,972	29	2,422	2,513
Total proved	8,745	69,540	696	21,031	18,820
Probable	3,890	21,933	266	7,812	6,483
Total proved plus probable	12,635	91,473	962	28,843	25,303

(1) May not add due to rounding.

(2) Gross reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

Net Present Value of Reserves – Forecast Prices and Costs ⁽¹⁾⁽²⁾

(including ARTC and before income taxes)

(\$ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	312,494	255,150	218,419	192,812	173,818
Developed non-producing	20,097	17,320	15,110	13,327	11,875
Undeveloped	37,888	23,707	16,203	11,645	8,596
Total proved	370,479	296,178	249,731	217,784	194,290
Probable	134,565	90,532	67,598	53,580	44,117
Total proved plus probable	505,044	386,710	317,329	271,364	238,407

(1) May not add due to rounding.

(2) As required by NI 51-101, undiscounted well abandonment costs of \$13.1 million for total proved reserves and \$14.8 million for total proved plus probable reserves are included in the Net Present Value determination.

Pricing Forecast ⁽¹⁾

	West Texas Intermediate US\$/bbl			Edmonton Reference Price Cdn\$/bbl			Natural Gas Price AECO "C" Cdn\$/mcf		
December 31	2004	2003	2002	2004	2003	2002	2004	2003	2002
2003	–	–	26.00	–	–	38.96	–	–	5.60
2004	–	29.00	24.00	–	37.61	35.86	–	6.00	5.20
2005	42.00	26.50	22.50	50.22	34.25	33.53	6.78	5.31	4.88
2006	40.00	25.50	22.95	47.76	32.90	34.20	6.52	4.83	4.94
2007	37.50	25.00	23.41	44.69	32.21	34.89	6.26	4.87	5.00
2008	35.00	25.50	23.88	41.62	32.85	35.59	6.00	4.92	5.06
2009	33.00	26.01	24.35	39.16	33.51	36.30	5.73	4.96	5.12
2010	33.50	26.53	24.84	39.75	34.18	37.02	5.85	5.01	5.18
2011	34.00	27.06	25.34	40.34	34.86	37.76	5.96	5.05	5.24
2012	34.50	27.60	25.85	40.92	35.56	38.52	6.08	5.15	5.30
2013	35.00	28.15	26.36	41.51	36.27	39.29	6.21	5.26	5.36
Thereafter (per year)	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

(1) Utilizing Paddock Lindstrom & Associates Ltd. January 1, 2005 price forecast.

Net Present Value of Reserves – Constant Prices and Costs ⁽¹⁾⁽²⁾

(including ARTC and before income taxes)

(\$ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	384,207	302,069	251,990	218,165	193,664
Developed non-producing	24,868	21,064	18,106	15,768	13,894
Undeveloped	48,032	29,624	20,274	14,683	10,974
Total proved	457,106	352,756	290,370	248,616	218,532
Probable	167,705	110,777	81,476	63,726	51,862
Total proved plus probable	624,812	463,533	371,846	312,342	270,394

(1) May not add due to rounding.

(2) Price assumptions: Cdn\$48.07/bbl Edmonton Reference price and Cdn\$6.88/mcf AECO "C" price.

Production by Area

	2004	2003	2002
Crude oil and NGL (bbls/d)			
Hays/Enchant	870	971	542
Neutral Hills	415	719	1,141
Consort	357	444	63
Alida	307	222	328
Sounding Lake	297	350	469
Ferrybank	204	80	7
Rocanville	155	147	159
Westerose	93	47	63
West Provost	86	92	93
Minor properties	509	280	383
Total	3,293	3,352	3,248
Natural gas (mcf/d)			
Scandia	12,225	4,725	934
Ferrybank	1,959	691	-
Atlee/Buffalo	1,669	1,879	1,884
West Provost	1,393	1,587	1,731
Westerose	1,251	671	759
Windfall	1,221	-	-
Ricinus	1,159	904	1,072
Judy Creek	932	-	-
Hays/Enchant	717	966	670
Minor properties	1,952	1,410	2,098
Total	24,478	12,833	9,148

Acreage Summary

(acres)	Total		Undeveloped		Fair Market Value*
	Gross	Net	Gross	Net	
Alberta	560,707	396,245	393,008	297,744	\$ 33,271,739
Saskatchewan	12,309	11,047	9,788	9,201	710,042
Total	573,016	407,292	402,796	306,945	\$ 33,981,781

* Seaton-Jordan & Associates Ltd. - undeveloped lands only

Drilling Activity

	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells						
Oil	6	5.3	4	4.0	3	2.5
Gas	22	18.1	14	11.8	10	8.5
Dry	8	7.5	12	11.2	12	7.3
Subtotal	36	30.9	30	27.0	25	18.3
Success rate (%)	78	76	60	59	52	60
Average working interest (%)	—	86	—	90	—	73
Operated wells	33	—	27	—	18	—
Development wells						
Oil	29	22.6	29	27.4	45	38.9
Gas	40	26.2	27	18.7	36	35.6
Dry	7	6.4	5	5.0	8	7.0
Subtotal	76	55.2	61	51.1	89	81.5
Success rate (%)	91	88	92	90	91	91
Average working interest (%)	—	73	—	84	—	91
Operated wells	64	—	49	—	87	—
Total wells						
Oil	35	27.9	33	31.4	48	41.4
Gas	62	44.3	41	30.5	46	44.1
Dry	15	13.9	17	16.2	20	14.3
Total	112	86.1	91	78.1	114	99.8
Success rate (%)	87	84	81	79	82	86
Average working interest (%)	—	77	—	86	—	87
Operated wells	97	—	76	—	105	—

Finding and On-Stream Costs ⁽¹⁾⁽²⁾

	2004	2003	2002 ⁽²⁾	2001 ⁽²⁾	2000 ⁽²⁾
Finding costs (\$ thousands)					
Land	13,378	9,143	4,408	3,170	2,575
Seismic	5,635	5,159	3,270	1,883	1,849
Drilling and completion	50,545	31,885	25,386	19,558	14,894
Acquisitions/dispositions <i>(net)</i>	(309)	(104)	13,087	2,331	32,165
Total finding costs	69,249	46,083	46,151	26,942	51,483
Facilities	21,062	13,416	8,119	7,768	3,646
Total on-stream costs	90,311	59,499	54,270	34,710	55,129
Reserve additions (mboe)(including acquisitions, dispositions and revisions)					
Proved	4,909	5,016	5,761	1,820	6,472
Proved plus probable	6,238	8,384	6,481	2,077	6,769
Finding cost per unit (\$/boe)					
Proved	14.10	9.19	8.01	14.80	7.95
Proved plus probable	11.10	5.50	7.12	12.97	7.61
On-stream cost per unit (\$/boe)					
Proved	18.39	11.86	9.42	19.07	8.52
Proved plus probable	14.48	7.10	8.37	16.71	8.14
Operating netback (\$/boe)	23.39	20.97	18.34	20.87	24.39
Recycle ratio					
Proved	1.27	1.77	1.95	1.09	2.86
Proved plus probable	1.62	2.95	2.19	1.25	2.99

(1) Excludes the net increase (decrease) in future development costs on proved reserves of (\$1.3) million, \$8.5 million, (\$1.1) million, \$4.2 million and \$1.2 million in 2004, 2003, 2002, 2001 and 2000 respectively; on proved plus probable reserves of \$3.0 million, \$10.8 million (\$0.5) million, \$4.4 million and \$1.2 million in 2004, 2003, 2002, 2001 and 2000 respectively.

(2) Represents proved plus 50 percent risked probable reserves.

	2004	3-Year Average	5-Year Average
Finding costs (\$ thousands)			
Land	13,378	8,735	6,390
Seismic	5,635	4,688	3,559
Drilling and completion	50,545	35,939	28,454
Acquisitions/dispositions (net)	(309)	4,466	9,579
Total finding costs	69,249	53,828	47,982
Facilities	21,062	14,199	10,802
Total on-stream costs	90,311	68,027	58,784
Reserve additions (mboe)(including acquisitions, dispositions and revisions)			
Proved	4,909	5,229	4,796
Proved plus probable	6,238	7,035	5,990
Finding cost per unit (\$/boe)			
Proved	14.10	10.29	10.01
Proved plus probable	11.10	7.65	8.01
On-stream cost per unit (\$/boe)			
Proved	18.39	13.01	12.26
Proved plus probable	14.48	9.67	9.81
Operating netback (\$/boe)	23.39	20.90	21.59
Recycle ratio			
Proved	1.27	1.61	1.76
Proved plus probable	1.62	2.16	2.20

Reserve Life Index

The Company's reserve life index using annualized fourth quarter production is 6.9 years for proved boe reserves compared to 7.8 years in 2003 and 9.5 years for proved plus probable boe reserves compared to 10.5 years in 2003. Reserve life calculated using annualized fourth quarter production may be more reflective of reserve life due to the active capital program and the level of new production added during the fourth quarter.

	2004	2004	2003	2003	2002 (1)	2002 (1)
	Using Annualized Q4 Production	Using Average Production	Using Annualized Q4 Production	Using Average Production	Using Annualized Q4 Production	Using Average Production
Production (mboe)	3,046	2,699	2,420	2,004	1,686	1,742
Proved reserves (mboe)	21,031	21,031	18,820	18,820	15,808	15,808
Proved reserve life index (years)	6.9	7.8	7.8	9.4	9.4	9.1
Proved plus probable reserves (mboe)	28,843	28,843	25,303	25,303	18,923	18,923
Proved plus probable reserve life index (years)	9.5	10.7	10.5	12.6	11.2	10.8

(1) Represents proved plus 50 percent risked probable reserves.

Finding and Development Costs (F&D)
and Finding, Development and Net Acquisition Costs (FD&A)⁽¹⁾

<i>Year ended December 31, 2004</i>	<i>Capital Expenditures (\$ 000s)</i>	<i>Total Proved Reserve Additions (mboe)</i>	<i>Total Proved Cost (\$/boe)</i>	<i>Total Proved plus Probable Reserve Additions (mboe)</i>	<i>Total Proved plus Probable Cost (\$/boe)</i>
F&D exploration and development program before revisions	90,620	5,875	15.42	9,175	9.88
F&D exploration and development program after revisions (a)	90,620	4,950	18.31	6,285	14.42
Change in total proved future development capital (b)	(1,276)	n/a	n/a	n/a	n/a
Change in total proved plus probable future development capital (c)	3,013	n/a	n/a	n/a	n/a
Total proved F&D including change in future development capital (d) equals (a+b)	89,344	4,950	18.05	n/a	n/a
Total proved plus probable F&D including change in future development capital (e) equals (a+c)	93,633	n/a	n/a	6,285	14.88
Net acquisition/disposition activity (f)	(309)	(41)	7.54	(47)	6.57
Total 2004 FD&A costs before future development costs (a+f)	90,311	4,909	18.40	6,238	14.48
Total 2004 proved FD&A costs including future development costs (d+f)	89,035	4,909	18.13	n/a	n/a
Total 2004 proved plus probable FD&A costs including future development costs (e+f)	93,324	n/a	n/a	6,238	14.96

⁽¹⁾ The aggregate of the exploration and development costs incurred in 2004 and the change in 2004 in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for 2004.

CORPORATE GOVERNANCE

Real's Board of Directors is comprised of six senior business executives with extensive knowledge and experience in the oil and gas industry. Each Director has a vested interest in the Company through common share ownership and stock options. During 2004, meetings included:

Full Board of Directors	six
Audit Committee	four
Compensation Committee	six
Reserve Audit Committee	three
Environmental, Health and Safety	one

The Directors of the Company adhere to guidelines defined in the Toronto Stock Exchange Report on Corporate Governance. The Board is responsible for the stewardship of the Company, the strategic planning process, the Company's succession plan, and the Company's internal control and management information systems.

The Board is comprised of six members, four of whom are independent and unrelated, including the Chairman of the Board. Additionally, the Audit, Compensation and Reserve Audit committees are comprised of non-management Directors. The entire Board conducts a self-assessment of its effectiveness annually. In addition, the entire Board evaluates the effectiveness of each committee and the contributions of individual directors. In assessing such matters, the Board conducts surveys of directors and makes recommendations for improvement. Further, the Board has placed a priority on good corporate governance practices. The entire Board develops the Company's approach to corporate governance issues, and regularly reviews the same.

At a minimum, on an annual basis, the full Board meets with management, separately from the budget process, to review and consider strategic planning. In addition, the Board reviews the strategic planning of the Company periodically in connection with regularly scheduled Board meetings and holds extraordinary strategic planning sessions based upon the need determined during the course of regularly scheduled Board meetings.

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS RESERVES DISCLOSURE ⁽¹⁾

Management of Real Resources Inc. (the Company) is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and
- (ii) the related estimated future net revenue.

An independent qualified reserves evaluator evaluated the Company's reserve data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with the Annual Information Form.

The Reserves Audit Committee of the Board of Directors of the Company has:

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.



Lowell E. Jackson, P. Eng
President and Chief Executive Officer



Frank P. Muller, P. Geol.
Vice President, Exploration



D. Nolan Blades, P. Eng.
Director

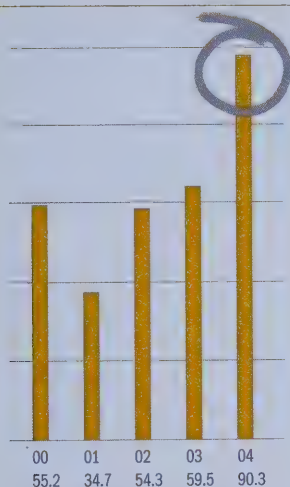


Frans Burger
Director

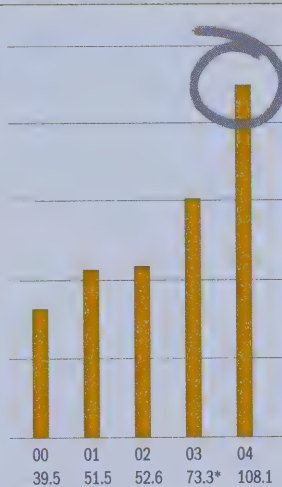
Calgary, Alberta, Canada
February 23, 2005

⁽¹⁾ Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

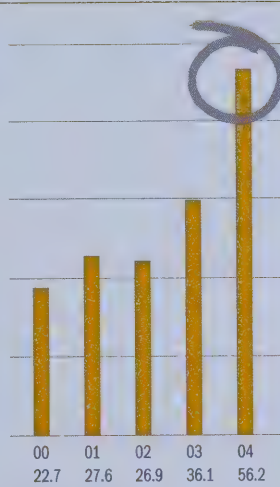
MANAGEMENT'S DISCUSSION AND ANALYSIS



Capital Expenditures (\$ millions)

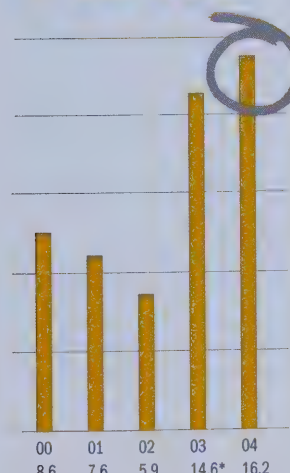


Revenue (\$ millions) *Restated

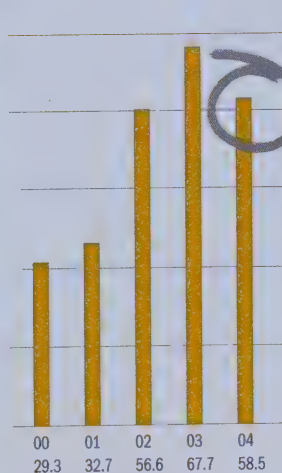


Cash Flow (\$ millions)

CREATING REAL VALUE YEAR-OVER- YEAR



Net Earnings (\$ millions) *Restated



Net Debt (\$ millions)



Shareholders' Equity (\$ millions) *Restated

The following discussion and analysis was prepared on March 15, 2005 and is management's assessment of Real's historical financial and operating results and should be read in conjunction with the audited Consolidated Financial Statements of the Company for the years ended December 31, 2004 and 2003 together with the notes related thereto. The reader should be aware that historical results are not necessarily indicative of future performance. This discussion contains forward-looking statements that involve risks and uncertainties. Such information, although considered reasonable by Real at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made. Where converted to a barrel of oil equivalent basis, all natural gas production results have been converted at the rate of six thousand cubic feet to one barrel of oil equivalent (boe).

Financial Highlights of 2004

The Company again achieved record activity levels in 2004, including a successful drilling program that resulted in a sixth consecutive year of growth in production revenue and total production volumes. All growth in 2004 was accomplished through the drill bit with a continued emphasis on natural gas prospects. Natural gas production in 2004 increased by 91 percent to 24.5 mmcf/d from 12.8 mmcf/d. Natural gas now makes up approximately 55 percent of the Company's overall production mix, successfully accomplishing Real's objective of placing equal emphasis on oil and natural gas activities.

Detailed Financial Analysis

PRODUCTION REVENUE

Production revenue summary (\$ thousands)	Years ended December 31		
	2004	2003	% change
Crude oil and liquids revenue	52,896	45,415	16
Natural gas revenue	58,990	29,611	99
	111,886	75,026	49
Hedging losses	(4,481)	(2,368)	89
Royalty income	698	624	12
Total production revenue	108,103	73,282	48

Production revenue from crude oil, liquids and natural gas sales increased by \$34.8 million or 48 percent to \$108.1 million in 2004 from \$73.3 million in 2003. Over 85 percent of the increase was the direct result of increased natural gas revenues. Production increases were primarily from the Southern Alberta core area (mainly Scandia), as well as from the Central Alberta (Ferrybank and Westeros) and the West Central Alberta (Windfall and Two Creeks) core areas. Overall, average natural gas production for the year increased by 91 percent to 24.5 mmcf/d from 12.8 mmcf/d in the previous year. Crude oil and liquids production decreased marginally to 3,293 bbls/d from 3,352 bbls/d in the previous year. Declines in the East Central Alberta core area (primarily at Neutral Hills) were partially offset by production additions in the Central Alberta core area (Ferrybank and Westeros). Fourth quarter 2004 drilling in Southeast Saskatchewan at Alida/Cantal will more than offset these declines in 2005.

The following table summarizes the commodity prices realized during 2004 and 2003.

Average realized price	Years ended December 31		
	2004	2003	% change
Crude oil and liquids (\$/bbl, excluding hedging)	43.89	37.12	18
Crude oil and liquids (\$/bbl, including hedging)	41.45	35.91	15
Natural gas (\$/mcf, excluding hedging)	6.58	6.32	4
Natural gas (\$/mcf, including hedging)	6.41	6.13	5
Total average realized price (\$/boe, including hedging)	39.80	36.25	10

Average realized price (\$/boe)	Years ended December 31		
	2004	2003	% change
Production revenue	41.46	37.43	11
Hedging losses	(1.66)	(1.18)	41
	39.80	36.25	10
Royalty income	0.26	0.31	(16)
Total average realized price	40.06	36.56	10

West Texas Intermediate (WTI) crude oil is the benchmark for North American oil prices and is the crude type against which NYMEX futures contracts are priced. Canadian crude oil prices are based upon refiners' postings at Alberta hubs such as Edmonton and Hardisty. These postings represent the WTI price at Cushing, Oklahoma less a transportation differential, the Canadian/US foreign exchange rate, and an adjustment for regional market conditions.

Real's average field prices reflect the refiners' posted price at the market centers, less adjustments for product quality relative to the posted product, and includes the quality differential on natural gas liquids.

Crude oil and liquids prices (\$/bbl, excluding hedging)	Years ended December 31		
	2004	2003	% change
WTI (\$US)*	41.40	31.06	33
Average exchange rate (\$Cdn/\$US)*	1.30	1.40	(7)
WTI (converted to \$Cdn)	53.82	43.53	24
Differential WTI to Edmonton (\$Cdn)	(1.28)	(0.43)	198
Edmonton light sweet posting (\$Cdn)*	52.54	43.10	22
Quality differential (including NGL differential)	(8.65)	(5.98)	45
Average realized price (\$Cdn)	43.89	37.12	18

*Source – CAPP Crude Oil Report – Refiner postings, Bank of Canada noon spot rate

The higher WTI benchmark price for crude oil during 2004 led to an 18 percent increase in Real's average crude oil and liquids price (before hedging) of \$43.89 per bbl compared to \$37.12 per bbl in 2003. The quality differential for crude oil and liquids increased in 2004 due to the higher relative increase in WTI postings compared to the Edmonton sweet price. There was also a widening in the differential in both Bow River Hardisty and Medium Sour Oil Hardisty reference prices, both of which are significant benchmarks in the Company's oil contracts.

Alberta natural gas prices are typically referenced to AECO "C".

Natural gas prices (\$/mcf, excluding hedging)	Years ended December 31		
	2004	2003	% change
AECO "C" *	6.55	6.68	(2)
Variance: Real pool price vs. spot	0.03	(0.36)	108
Average realized natural gas price	6.58	6.32	4

*Source – CAPP Natural Gas Report – calendar month average of daily cash prices (weighted)

A change in the composition of the gas contracts was the primary reason for the four percent increase in average natural gas prices realized (before hedging) of \$6.58 per mcf compared to \$6.32 per mcf in 2003. Substantially all of Real's natural gas production is now tied to spot prices, whereas a significant proportion had been tied to aggregator contracts prior to the tie-in of Scandia production in October 2003.

The following table summarizes the impact of the Company's production activities, prices and hedging activities on oil and gas revenue:

Variance analysis	(\$ millions)	% change
Reported 2003 production revenue	73.3	
Increase due to gas production volumes	27.0	78
Increase due to realized oil and liquids price	8.1	23
Increase due to realized gas price	2.4	7
Decrease due to hedging activities	(2.1)	(6)
Other (net)	(0.6)	(2)
Total increase, net	34.8	100
Reported 2004 production revenue	108.1	

Royalty Expense

Royalties increased by 53 percent to \$23.1 million in 2004 from \$15.1 million in 2003. This increase was the direct result of higher oil and gas revenues. Royalties (net of ARTC), as a percentage of gross revenue, have not changed materially although the composition of production has changed significantly. The large amount of new production in 2004 increased the average Freehold and GORR royalty rate somewhat and reduced the average Crown rate slightly.

Royalty expense (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Crown	16,198	11,119	46
Freehold and GORR	7,312	4,373	67
Total royalties	23,510	15,492	52
ARTC	(443)	(414)	7
Total royalties, net of ARTC	23,067	15,078	53
Total royalties (\$/boe)	8.71	7.73	13
Total royalties, net of ARTC (\$/boe)	8.55	7.52	14

Average royalty rates (% of revenue, excluding hedging activities)	Years ended December 31		
	2004	2003	% change
Crown	14.5	14.8	(2)
Freehold and GORR	6.5	5.8	12
Total royalties	21.0	20.6	2
ARTC	(0.4)	(0.5)	(20)
Total royalties, net of ARTC	20.6	20.1	2

Other Income

The Company settled a legal dispute with a third-party gas processor relating to the processing of contracted gas volumes from Real's Scandia project in the first half of 2003. The settlement included a \$0.6 million cash payment to Real plus a revised gas processing agreement.

Operating Expenses

Operating expenses in 2004 increased by 33 percent to \$20.0 million from \$15.1 million in 2003 due to increased production volumes. There was upward pressure on the overall operating cost structure through 2004 that was directly related to increased industry activity in Western Canada. On the other hand, operating expenses on a unit-of-production basis decreased to \$7.42 per boe in 2004 from \$7.52 per boe in 2003. The improvement was due to the Company's production mix becoming more gas-weighted.

Operating expenses (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Operating expenses	20,019	15,075	33
Operating expenses (\$/boe)	7.42	7.52	(1)

Transportation Costs

Transportation costs in 2004 increased by 69 percent to \$1.9 million from \$1.1 million in 2003, primarily as a result of increased production volumes. Transportation costs on a unit-of-production basis increased to \$0.70 per boe in 2004 from \$0.55 per boe during 2003 due to the increased relative proportion of gas production that has a higher unit rate (see operating netbacks).

Transportation costs (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Transportation costs	1,879	1,110	69
Transportation costs (\$/boe)	0.70	0.55	27

Operating Netback

Operating netbacks (excluding hedging losses and ARTC) increased 13 percent to \$24.89 per boe for 2004 compared to \$21.94 per boe for 2003. This increase was primarily due to higher Edmonton light sweet postings, and to a lesser extent, better differentials on AECO postings due to the composition of gas contracts.

Operating netback (\$/boe)	Years ended December 31		
	2004	2003	% change
Production revenue (excluding hedging losses)	41.46	37.43	11
Royalty income	0.26	0.31	(16)
	41.72	37.74	11
Total royalties (excluding ARTC)	(8.71)	(7.73)	13
Operating expenses	(7.42)	(7.52)	(1)
Transportation costs	(0.70)	(0.55)	27
Operating netback	24.89	21.94	13

Operating netback – crude oil properties (\$/bbl)	Years ended December 31		
	2004	2003	% change
Production revenue (excluding hedging losses)	43.77	37.16	18
Royalty income	0.27	0.29	(7)
	44.04	37.45	18
Total royalties (excluding ARTC)	(8.49)	(7.59)	12
Operating expenses	(9.58)	(8.27)	16
Transportation costs	(0.41)	(0.27)	52
Operating netback	25.56	21.32	20

Operating netback – natural gas properties*	Years ended December 31		
	2004	2003	% change
Production revenue (excluding hedging losses)	6.69	6.30	6
Royalty income	0.04	0.06	(33)
	6.73	6.36	6
Total royalties (excluding ARTC)	(1.47)	(1.32)	11
Operating expenses	(1.03)	(1.08)	(5)
Transportation costs	(0.14)	(0.16)	(13)
Operating netback	4.09	3.80	8

* (\$/mcf, includes natural gas liquids production converted on basis of 1 bbl = 6 mcf)

General and Administrative Expenses

Gross general and administrative expenses increased 27 percent to \$7.7 million in 2004 compared to \$6.0 million in 2003. The increase reflects the addition of full-time staff associated with the Company's growth. The majority were exploration staff which is reflected in higher capitalized costs. On a unit-of-production basis, net general and administrative expenses decreased 11 percent to \$1.41 per boe from \$1.59 per boe, reflecting continued improvement in operating efficiencies.

General and administrative expenses (\$ thousands)	Years ended December 31		
	2004	2003	% change
Gross expense	7,666	6,049	27
Overhead recoveries	(1,926)	(1,625)	19
Subtotal	5,740	4,424	30
Capitalized expense	(1,943)	(1,228)	58
Net expense	3,797	3,196	19

Average cost per barrel of oil equivalent (\$/boe)	Years ended December 31		
	2004	2003	% change
Gross expense	2.84	3.02	(6)
Overhead recoveries	(0.71)	(0.81)	(12)
Subtotal	2.13	2.21	(4)
Capitalized expense	(0.72)	(0.62)	16
Net expense	1.41	1.59	(11)

Stock-Based Compensation

Stock-based compensation costs in 2004 remained consistent with 2003.

Stock-based compensation (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Stock-based compensation	446	445	—
Stock-based compensation (\$/boe)	0.17	0.22	(23)

Interest Expense

Interest expense for 2004 decreased 11 percent to \$2.1 million from \$2.4 million in 2003. Average debt levels during 2004 were marginally lower than during 2003. The reduction in interest expense was due to the continued decrease in general interest rates. The all-inclusive cost of borrowing averaged 4.1 percent in 2004 compared to 4.5 percent in 2003.

Interest expense (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Interest expense	2,141	2,401	(11)
Interest expense (\$/boe)	0.79	1.20	(34)
Average debt outstanding	52,000	53,000	(2)
Average effective interest rate (%)	4.1	4.5	(9)

Depletion, Depreciation and Accretion (DD&A)

DD&A expense increased 46 percent to \$30.3 million in 2004 from \$20.8 million in 2003, based primarily on higher production levels. DD&A increased to \$11.22 per boe during 2004 compared to \$10.37 per boe in 2003. Increased overall industry activity during the last year has put pressure on capital costs, resulting in marginally higher DD&A rates.

Depletion, depreciation and accretion (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Depletion and depreciation	29,396	20,042	47
Accretion on asset retirement obligation	873	738	18
	30,269	20,780	46
Depletion, depreciation and accretion (\$/boe)	11.22	10.37	8

Ceiling Test

Real performs a ceiling test calculation at least annually in accordance with the Canadian Institute of Chartered Accountants' full cost accounting guidelines. The recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then impairment would be recognized on the amount by which the carrying amount of the assets exceeds the present value of expected cash flows using proved and probable reserves and expected future prices and costs. No write-down was required for the year ended December 31, 2004, based on expected future commodity prices of \$39.38 per barrel for crude oil and \$6.39 per mcf for natural gas. No write-down was required for the year ended December 31, 2003, based on year-end commodity prices of \$40.92 per barrel for crude oil and \$6.08 per mcf for natural gas.

Taxes

The Company's future income tax expense was \$9.5 million for 2004, up substantially from the \$0.5 million recorded in 2003. This increase was primarily due to a one-time recovery of \$7.0 million related to the changes in the Federal and Alberta corporate tax rates in 2003 that were announced in June 2003. Higher production revenues in 2004 also contributed approximately \$3.7 million to the increase in future income tax expense. The first quarter of 2004 included a one-time recovery of \$0.8 million related to a reduction in the Alberta corporate tax rate.

The Company's capital tax expense of \$0.8 million for 2004 increased nine percent from \$0.7 million in the preceding year. The increase in the Large Corporation Tax base was offset by the increase in the capital deduction from \$10 million to \$50 million that was enacted by the Federal Government in 2004. Real paid no current income tax in 2004.

Taxes (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Future income taxes	9,543	480	1,888
Effective income tax rate (%)	36	3	1,100
Capital taxes	787	720	9
Total taxes	10,330	1,200	761
Total taxes (\$/boe)	3.83	0.60	538

At the end of 2004, Real had approximately \$132.8 million of accumulated tax pools that are available for deduction against future earnings compared to \$96.2 million at December 31, 2003.

Summary of tax pools at December 31, 2004 (\$ thousands)	<i>Maximum available balance</i>	<i>Maximum annual deduction</i>
Canadian exploration expense	10,941	100%
Canadian development expense	39,103	30%
Canadian oil & gas property expense	39,111	10%
Undepreciated capital cost	40,139	4-30%
Foreign exploration & development expense	354	10%
Other	3,168	8-20%
Total	132,816	

The tax pools at December 31, 2004 are net of \$0.6 million of Canadian Exploration Expense qualifying expenditures that were incurred prior to December 31, 2004 pursuant to the December 16, 2004 flow-through share equity offering. The remaining \$19.4 million of Canadian Exploration Expense qualifying expenditures are expected to be incurred prior to March 31, 2005.

Net Earnings, Netbacks and Cash Flow from Operations

Net Earnings

Net earnings increased 11 percent to \$16.2 million in 2004 from \$14.6 million in 2003. Basic net earnings per share decreased six percent to \$0.60 per share in 2004 from \$0.64 per share in 2003. Similarly, diluted net earnings per share decreased eight percent to \$0.58 per share in 2004 from \$0.63 per share in 2003.

Netbacks (\$/boe)	<i>Years ended December 31</i>		
	<i>2004</i>	<i>2003</i>	<i>% change</i>
Production revenue	40.06	36.56	10
Net royalties	(8.55)	(7.52)	14
Operating expenses	(7.42)	(7.52)	(1)
Transportation costs	(0.70)	(0.55)	27
Operating netback	23.39	20.97	12
Other income	–	0.30	(100)
General and administrative expenses	(1.41)	(1.59)	(11)
Interest expense	(0.79)	(1.20)	(34)
Current taxes	(0.29)	(0.36)	(19)
Cash flow netback (before abandonment)	20.90	18.12	15
Depletion, depreciation and accretion	(11.22)	(10.37)	8
Future income taxes	(3.54)	(0.24)	1,375
Stock-based compensation	(0.17)	(0.22)	(23)
Corporate netback (before abandonment)	5.97	7.29	(18)

Cash Flow from Operations

Cash flow from operations increased 55 percent to \$56.2 million in 2004 from \$36.1 million in 2003. Cash flow from operations per basic share increased 32 percent to \$2.09 per share in 2004 from \$1.58 per share in 2003. Cash flow from operations per diluted share increased 30 percent to \$2.03 per share from \$1.56 per share.

(\$ thousands)	Years ended December 31		
	2004	2003	% change
Net earnings	16,155	14,597	11
Non cash items:			
Depletion, depreciation and accretion	30,269	20,780	46
Future income tax expense	9,543	480	1,888
Stock-based compensation	446	445	—
Abandonment expenditures	(240)	(160)	50
Cash flow from operations	56,173	36,142	55

(thousands)	Years ended December 31		
	2004	2003	% change
Weighted average outstanding shares			
Basic	26,932	22,804	18
Diluted	27,724	23,226	19
Outstanding shares at December 31			
Basic	29,090	23,351	25
Diluted	29,882	23,774	26

Per share information (\$ thousands, except where noted)	Years ended December 31		
	2004	2003	% change
Net earnings	16,155	14,597	11
Basic (\$/share)	0.60	0.64	(6)
Diluted (\$/share)	0.58	0.63	(8)
Cash flow from operations	56,173	36,142	55
Basic (\$/share)	2.09	1.58	32
Diluted (\$/share)	2.03	1.56	30
Total assets	279,656	211,967	32
Basic (\$/share)	10.38	9.30	12
Diluted (\$/share)	10.09	9.13	11
Book value (shareholders' equity)	143,994	89,580	61
Basic (\$/share)	5.35	3.93	36
Diluted (\$/share)	5.19	3.86	34

Capital Expenditures

Real executes its growth strategy through exploration, exploitation and development activities, supplemented with strategic property and corporate acquisitions. Net capital expenditures in 2004 before asset retirement obligation and future tax gross-ups were \$90.3 million compared to \$59.5 million in 2003. These expenditures are summarized as follows:

Capital expenditures (\$ thousands)	Years ended December 31		
	2004	2003	% change
Exploration and development expenditures			
Lease acquisition	13,378	9,143	46
Geological and geophysical	5,635	5,159	9
Drilling and completion	50,545	31,885	59
Facilities and equipment	20,768	13,199	57
Total exploration and development expenditures	90,326	59,386	52
Other expenditures	294	217	35
Gross capital expenditures	90,620	59,603	52
Proceeds from property dispositions	(309)	(104)	197
Net capital expenditures before the following:	90,311	59,499	52
Asset retirement obligation	1,195	1,112	7
Future income tax gross-up on acquisitions	—	65	(100)
Net capital expenditures	91,506	60,676	51

Funding for capital expenditures and acquisitions was provided for by cash flow from operations, the proceeds from the issuance of equity, bank debt and working capital.

Capitalization and Financial Resources

At December 31, 2004 the Company had a \$95 million financing commitment with a Canadian chartered bank, which provided for an extendible revolving-term credit facility. At the end of the year, Real had drawn \$46.2 million of the facility.

In addition to this debt, Real had a working capital deficiency of \$12.3 million for a total net debt of \$58.5 million. The ratio of total net debt as at December 31, 2004 to 2004 cash flow was 1.0 times and the ratio of total net debt as at December 31, 2004 to the annualized fourth quarter 2004 cash flow was 0.8 times.

Outstanding Share Data

The Company is authorized to issue an unlimited number of common shares without par value, and an unlimited number of first, second, third and fourth class preferred shares issuable in series. As at December 31, 2004, Real had 29.1 million outstanding common shares compared to 23.4 million outstanding shares at December 31, 2003. Real had no preferred shares outstanding during these periods. Employees and directors have been granted options to purchase common shares under the Company Stock Option Plan. This plan and its terms and outstanding balance are disclosed in note 6(e) to the Consolidated Financial Statements.

The Company obtained regulatory approval under Canadian securities laws to purchase common shares under three consecutive Normal Course Issuer Bids which commenced in June 2002 and will continue until June 2005. Under the terms of the bids, the Company repurchased for cancellation 0.3 million common shares in 2004 and 0.7 million common shares in 2003. As of December 31, 2004, Real was entitled to purchase for cancellation an additional 1.3 million common shares.

Contractual Obligations

The Company has entered into various commitments primarily related to the Calgary office lease. The following table summarizes the outstanding contractual obligations of the Company for the next five years and thereafter:

(\$ thousands)	2005	2006	2007	2008	2009	Thereafter	Total
Office lease	343	381	381	381	63	—	1,549
Pipeline transportation	175	117	—	—	—	—	292
Other	207	106	25	—	—	—	338
	725	604	406	381	63	—	2,179

Off-Balance Sheet Arrangements and Related Party Transactions

The Company has not entered into any off-Balance Sheet transactions or into any related party transactions.

Critical Accounting Estimates

Management is often required to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. A comprehensive discussion of the Company's significant accounting policies is contained in note 2 to the annual Consolidated Financial Statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

(a) Full cost accounting

The Company follows the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproven properties, and estimated future development costs, is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point the costs are included in the total cost base for purposes of calculating depletion and for evaluating impairment.

The alternative method of accounting for oil and natural gas properties and equipment is the successful efforts method. The major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs are charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment.

(b) Oil and natural gas reserves

The Company's proved oil and gas reserves are 100 percent evaluated and reported by an independent petroleum engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

(c) Full cost accounting ceiling test

The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment is determined when the carrying value of the Company's property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third-party quoted forward prices and are adjusted for the Company's contract prices and quality differentials. If impairment is deemed to occur, the magnitude is calculated by comparing the carrying value of property, plant and equipment to the estimated net present value of future cash flows from proved plus risked probable reserves. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of future cash flows would be recorded as a permanent impairment and charged as additional depletion expense in the Consolidated Statement of Earnings. No write-down was required at December 31, 2004.

(d) Asset retirement obligation

The Company recognizes the fair value of its asset retirement obligation (ARO) in the period in which it is incurred and when a reasonable estimate of its obligation can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period with the passage of time and the amount of this accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual cost incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs.

Determinations of the original undiscounted costs are based on engineering estimates using current costs and technology in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth and area-specific environmental legislation.

(e) Future income tax

The Company follows the liability method of accounting for income taxes. Under this method income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax base, using substantively enacted future income tax rates. In June 2003, the Federal Government introduced a gradual reduction in the general corporate income tax rate over a five-year period starting January 1, 2003 (see Taxes in the MD&A). The impact of the new Federal legislation requires the Company to schedule all existing temporary differences, identify the accounting and tax values during the five-year phase-in period for the declining tax rates and recalculate the future income tax balance using tax rates in effect when temporary differences reverse. The above-noted forecasts of estimated net revenue streams are utilized to calculate the future tax provision and, as such, are subject to revisions, both upwards and downwards, that are not known at this time. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of future taxes determined at a point in time. To the extent that these differences are created, they can impact the charge against earnings for future income taxes.

(f) Stock-based compensation

The Company's Stock Option Plan provides for the granting of options to directors, officers and employees. The Company uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at fair value at the grant date and expensed over the expected exercise time-frame with a corresponding increase to contributed surplus. Upon exercise of stock options, consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is recorded as an increase in share capital.

Changes in Accounting Policies During the Current Fiscal Year

The following new and amended standards were implemented by the Company in 2004 with the following impact on the 2003 financial statements where retroactive application was required:

(a) Asset retirement obligation

The Canadian Institute of Chartered Accountants (CICA) issued Section 3110 which requires the recognition of the fair value of the retirement obligation for related long-term assets as a liability. Retirement costs equal to the retirement obligation are capitalized as part of the associated capital cost and amortized to expense through depletion over the life of the asset. In subsequent periods, the liability is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. This standard was adopted effective January 1, 2004 and prior period comparative balances have been restated. As a result of implementation, the standard had the following effects on the Company's Consolidated Financial Statements:

Changes to Consolidated Balance Sheet (\$ thousands)	<i>January 1, 2004</i>
Increase in property, plant and equipment (net of accumulated depletion and depreciation)	6,862
Increase in asset retirement obligation	6,949
Decrease in future income tax liability	49
Decrease in retained earnings	38

(b) Stock-based compensation

In September 2003, the CICA issued an amendment to Section 3870 "Stock-based Compensation and Other Stock-based Payments". The amended section is effective for fiscal years beginning on or after January 1, 2004. The amendment requires that companies measure all stock-based payments using the fair value method of accounting and recognize the compensation expense in their financial statements. This standard was adopted effective January 1, 2004, and as required by the transitional provisions the prior period comparative balances have been restated for options issued on or after January 1, 2002. As a result of implementation, the standard had the following impact on the Company's Consolidated Financial Statements:

Changes to Consolidated Balance Sheet (\$ thousands)	<i>January 1, 2004</i>
Increase in common stock	34
Increase in contributed surplus	682
Decrease in retained earnings	716

(c) Full cost accounting

In September 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost." The Guideline modifies the ceiling test, which limits the aggregate capitalized costs that may be carried forward to future periods. Specific new guidance was provided on several issues, including the frequency of conducting impairment tests, the testing for recoverability and the method of determining fair value. The Guideline recommends that the impairment test should be conducted at each Balance Sheet date. The recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then impairment should be recognized on the amount by which the carrying amount of the assets exceeds the present value of expected cash flows using proved and probable reserves and expected future prices and costs. The effective date of the Guideline is for fiscal years beginning on or after January 1, 2004. The implementation of this guideline had no effect on the Company's Consolidated Financial Statements.

(d) Hedging relationships

In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships". The effective date of this Guideline was deferred to fiscal years beginning on or after July 1, 2003. The Guideline addresses the type of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness. The Guideline does not specify how hedge accounting should be applied but does require that financial instruments not designated as hedges be recorded at fair value on the Company's Consolidated Balance Sheet, with changes in fair value recorded in earnings. As a result of implementation, the standard had the following impact on the Company's Consolidated Financial Statements:

Changes to Consolidated Balance Sheet (\$ thousands)	<i>January 1, 2004</i>
Increase in deferred changes	868
Increase in financial instrument liability	868

(e) Transportation costs

In accordance with Section 1100 of the CICA Handbook, transportation costs are no longer netted against oil and natural gas revenue, but are disclosed as a separate expense in the Consolidated Statement of Operations and Retained Earnings.

(f) Flow-through shares

Effective January 1, 2004, Real prospectively adopted a new Canadian accounting standard relating to accounting for flow-through shares as described in note 2(m) to the Consolidated Financial Statements. The future tax liability and share capital were adjusted when the shares were issued. There were no changes to net income, petroleum and natural gas properties and equipment or any other reported amounts in the financial statements as a result of adopting the standard.

Impact on Net Income of Change in Accounting Policies

The implementation of new accounting policies in 2004 related to the asset retirement obligation and stock-based compensation have resulted in the restatement of previously reported annual and quarterly net income. The restatements were required under the transitional provisions of the respective accounting standards.

The following table illustrates the impact of the new accounting policies on quarterly net income for 2003:

	2003				
(\$ thousands)	Q1	Q2	Q3	Q4	Total
Net income before changes in accounting policies ⁽¹⁾	3,106	6,920	3,153	2,204	15,383
Increase(decrease) in net income:					
Stock-based compensation ⁽²⁾	(87)	(115)	(120)	(123)	(445)
Depletion and accretion on asset retirement obligation ⁽³⁾	(135)	(157)	(150)	(91)	(533)
Future income tax recovery ⁽⁴⁾	57	54	50	31	192
Net income after changes in accounting policies	2,941	6,702	2,933	2,021	14,597

(1) This represents net income as reported before retroactive restatement for changes in accounting policies.

(2) The new accounting policy for stock-based compensation was implemented in the first quarter of 2004. The four quarters of 2003 have been restated as a result of this new policy which required restatement of prior periods for comparative purposes.

(3) The new accounting policy for asset retirement obligations was implemented in the first quarter of 2004. The four quarters of 2003 have been restated as a result of the new policy which required restatement of prior periods for comparative purposes.

(4) Future income tax recovery has been restated to reflect the impact of the retroactive restatement of prior periods in accounting for asset retirement obligation.

Impact of New Accounting Pronouncements

There are no new accounting pronouncements which impact the Consolidated Financial Statements of Real.

Risks and Uncertainties

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following discussion reviews the general and specific risks as well as Real's approach to managing these risks.

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Real's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, and currency exchange rates. Operational risks include competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The Company minimizes its business risks by operating a large number of its properties. This enables Real to control the timing, direction and costs related to exploration and development opportunities. Real's geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success. The Company closely follows all government regulations and has an up-to-date emergency response plan that has been communicated to field operations by management. Real also carries insurance coverage to protect itself against potential losses. Maintaining a highly motivated and talented staff of petroleum and natural gas professionals further minimizes the business risk.

Real relies on various sources of funding to support its growing capital expenditure program:

- Internally-generated cash flow provides a minimum level of funding on which the Company's annual capital expenditure program is based;
- Debt may be utilized to expand capital programs when appropriate; and
- New equity, if available on favourable terms, may be utilized to expand exploration programs.

The Company is exposed to commodity price and market risk for its principal products of petroleum and natural gas. Commodity prices are influenced by a wide variety of factors, most of which are beyond Real's control. To manage this risk, the Company has in the past entered into a number of short-term financial derivatives for hedging purposes. These derivatives included contracts related to oil and gas prices, as well as foreign exchange rates. Real has also minimized its exposure to increased rates by entering into short-term contracts for interest-rate swap. The Company continues to monitor the cost and associated benefit of these instruments as well as debt levels and utilization rates on bank lines and will utilize these derivatives when warranted.

Inflation subjects the Company to potential erosion of product netbacks. For example, increased domestic prices for oil and natural gas production equipment and services can inflate the costs of operations.

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce them in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long-term relationships with suppliers and contractors and maintaining an appropriate inventory of production equipment.

Demand for crude oil and natural gas produced by the Company exists within Canada and the United States; however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Demand for natural gas liquids is influenced mainly by the demand for petrochemicals in North American and offshore markets. Real mitigates these risks as follows:

- Crude oil production is of a high quality and hence not subject to adverse quality differentials;
- Natural gas is connected to a mature pipeline infrastructure that operates with minimal interruptions;
- Exploration efforts target high-quality oil and liquids-rich natural gas reserves;
- Exploration efforts are concentrated in core regions where marketing expertise levels are highest. Marketing synergies can be achieved with the existing production base;
- Sale arrangements vary in term and pricing structure, creating a diverse portfolio that minimizes risk of exposure to any one market; and
- Financial instruments are used where appropriate to manage commodity price volatility.

In 1994, the United Nations' Framework on Climate Change came into force and three years later led to the Kyoto Protocol, which requires nations to reduce their emissions of carbon dioxide and, therefore, greenhouse gases. The Government of Canada has ratified the Kyoto Protocol. Producers in geographic areas where Real operates may be required to reduce greenhouse gases. This could result in, among other things, increased operating and capital expenditures for those producers. This could make certain production of crude oil or natural gas by those producers uneconomic, resulting in reductions in such production. The Company is unable to predict the effect on its future earnings of the ratification of the Kyoto Protocol by the Federal Government.

The Company is committed to maximizing shareholder value in an environmentally and socially responsible and safe manner. To this end, Real is actively involved in the Canadian Petroleum Producers (CAPP) Stewardship initiative. This voluntary initiative encourages members to continually improve their environment, health and safety performance and to report their progress to all stakeholders. The Company is pleased to report that CAPP has recognized Real's participation at a Gold level, which acknowledges an open and transparent account of our environment, health and safety performance on a yearly basis and a leadership role in the improvement of these issues.

Selected Annual Information

(\$ thousands, except per share amounts)	Years ended December 31		
	2004	2003*	2002
Working interest production			
Crude oil and liquids (bbls/d)	3,293	3,352	3,248
Natural gas (mcf/d)	24,478	12,833	9,148
Total oil equivalent (boe/d)	7,373	5,491	4,772
Production revenue	108,103	73,282	52,554
Cash flow from operations	56,173	36,142	26,829
Per share – basic	2.09	1.58	1.36
Per share – diluted	2.03	1.56	1.34
Net earnings	16,155	14,597	5,907
Per share – basic	0.60	0.64	0.30
Per share – diluted	0.58	0.63	0.29
Total assets	279,656	211,967	163,346
Total net debt	58,498	67,697	56,570

*Restated

Summary of Quarterly Results

(\$ thousands, except per share amounts)	Three months ended 2004				Annual 2004
	March 31	June 30	Sept 30	Dec 31	
Working interest production					
Crude oil and liquids (bbls/d)	3,281	3,090	3,017	3,783	3,293
Natural gas (mcf/d)	21,784	23,617	25,113	27,360	24,478
Total oil equivalent (boe/d)	6,911	7,027	7,203	8,344	7,373
Production revenue	22,869	25,546	26,966	32,722	108,103
Cash flow from operations	11,420	12,791	14,653	17,309	56,173
Per share – basic	\$ 0.47	\$ 0.46	\$ 0.53	\$ 0.63	\$ 2.09
Per share – diluted	\$ 0.46	\$ 0.45	\$ 0.52	\$ 0.60	\$ 2.03
Net earnings	3,004	3,313	3,863	5,975	16,155
Per share – basic	\$ 0.12	\$ 0.12	\$ 0.14	\$ 0.22	\$ 0.60
Per share – diluted	\$ 0.12	\$ 0.12	\$ 0.13	\$ 0.21	\$ 0.58
Total assets	227,636	245,579	265,295	279,656	279,656
Total net debt	51,509	63,607	75,540	58,498	58,498

(\$ thousands, except per share amounts)	Three months ended 2003*				Annual 2003
	March 31	June 30	Sept 30	Dec 31	
Working interest production					
Crude oil and liquids (bbls/d)	3,518	3,034	3,420	3,436	3,352
Natural gas (mcf/d)	9,827	9,201	13,357	18,840	12,833
Total oil equivalent (boe/d)	5,156	4,567	5,646	6,576	5,491
Production revenue	19,222	15,227	18,020	20,813	73,282
Cash flow from operations	9,711	6,955	9,547	9,929	36,142
Per share – basic	\$ 0.46	\$ 0.30	\$ 0.41	\$ 0.41	\$ 1.58
Per share – diluted	\$ 0.45	\$ 0.30	\$ 0.40	\$ 0.41	\$ 1.56
Net earnings	2,941	6,702	2,933	2,021	14,597
Per share – basic	\$ 0.14	\$ 0.29	\$ 0.13	\$ 0.08	\$ 0.64
Per share – diluted	\$ 0.14	\$ 0.29	\$ 0.12	\$ 0.08	\$ 0.63
Total assets	180,860	195,714	209,224	211,967	211,967
Total net debt	48,914	60,054	69,918	67,697	67,967

*Restated

Fourth Quarter 2004 Results

Capital expenditures totalled \$19.9 million for the fourth quarter which included drilling 17 (13.4 net) wells. Real spent \$3.7 million on land and property acquisitions, \$1.1 million on seismic, \$11.7 million on drilling and completions and \$3.4 million on facilities. The capital program was financed through a combination of funds generated from operations and proceeds from the equity issue.

Operationally, Real brought on new production from the Alida/Cantal property. Real increased its average production to 8,344 boe/d in the fourth quarter from 7,203 boe/d in the third quarter of 2004 as a result of this new production. Consistent with increased production, Real recorded gains in production revenue, cash flow from operations and net income in the fourth quarter of 2004 as compared to the third quarter of 2004 and also compared to the fourth quarter of 2003.

In December 2004 Real completed a flow-through share equity offering for a total of 1.27 million common shares at a price of \$15.75 per share for gross proceeds of \$20.0 million. As a result, Real has a commitment to spend \$20.0 million on qualifying Canadian Exploration Expenditures prior to December 31, 2005. All have been renounced to subscribers effective December 31, 2004.

Netback (\$/boe)	Three months ended December 31		
	2004	2003	% change
Production revenue	42.62	34.41	24
Net royalties	(7.82)	(6.74)	16
Operating expenses	(7.60)	(7.33)	4
Transportation costs	(0.77)	(0.63)	22
Operating netback	26.43	19.71	34
General and administrative expenses	(1.58)	(1.73)	(9)
Interest expense	(0.76)	(1.09)	(30)
Current taxes	(0.33)	(0.30)	10
Cash flow netback <i>(before abandonment)</i>	23.76	16.59	43
Depletion, depreciation and accretion	(11.62)	(10.51)	11
Future income taxes	(4.18)	(2.54)	65
Stock-based compensation	(0.19)	(0.20)	(5)
Corporate netback <i>(before abandonment)</i>	7.77	3.34	133

CEO/CFO CERTIFICATION FORM 52-109FT1

I Lowell E. Jackson, President and Chief Executive Officer of Real Resources Inc. certify that:

- (1) I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings) of Real Resources Inc. (the issuer) for the year ending December 31, 2004;
- (2) Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings; and
- (3) Based on my knowledge, the annual financial statements together with other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings.

Date: March 15, 2005



Lowell E. Jackson, P. Eng
President and Chief Executive Officer

I Pamela J. Orr, Vice President Finance and Chief Financial Officer of Real Resources Inc. certify that:

- (1) I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings) of Real Resources Inc. (the issuer) for the year ending December 31, 2004;
- (2) Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings; and
- (3) Based on my knowledge, the annual financial statements together with other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings.

Date: March 15, 2005



Pamela J. Orr, CA, CFA
Vice President Finance and Chief Financial Officer

MANAGEMENT'S RESPONSIBILITY STATEMENT

TO THE SHAREHOLDERS OF REAL RESOURCES INC.

The accompanying consolidated financial statements and all other financial information presented in this annual report are the responsibility of Real's management. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Management has developed and maintains systems of internal accounting controls, policies and procedures in order to provide for the safeguarding of assets and preparation of relevant, reliable and timely financial information.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee reviews these statements with management and the auditors and reports to the Board of Directors who approve the financial statements.



Pamela J. Orr, CA, CFA
Vice President Finance & Chief Financial Officer

Calgary, Alberta, Canada
March 15, 2005



Lowell E. Jackson, P. Eng.
President & Chief Executive Officer

AUDITORS' REPORT

To the Shareholders of Real Resources Inc.

We have audited the consolidated balance sheets of Real Resources Inc. as at December 31, 2004 and 2003 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also included assessing the accounting principles used and significant estimates made by management, as well evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all materials respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
March 15, 2005

CONSOLIDATED BALANCE SHEETS

<i>December 31, 2004 and 2003 (\$ thousands)</i>	<i>2004</i>	<i>2003*</i>
ASSETS		
Current assets		
Accounts receivable	15,634	9,876
Prepaid expenses	1,129	1,308
	16,763	11,184
Property, plant and equipment <i>(note 4)</i>	262,893	200,783
	279,656	211,967
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	29,026	16,628
Long-term debt <i>(note 5)</i>	46,235	62,253
Asset retirement obligation <i>(notes 3(b) and 9)</i>	13,635	11,807
Future income taxes <i>(note 7)</i>	46,766	31,699
Shareholders' equity		
Share capital <i>(note 6)</i>	91,767	52,693
Contributed surplus <i>(notes 3(d) and 10)</i>	1,048	682
Retained earnings	51,179	36,205
	143,994	89,580
	279,656	211,967

* Restated (see note 3)

Commitments (see note 8)

Subsequent event (see note 12)

See accompanying notes to Consolidated Financial Statements



Robert B. Michaleski, CA
Director



Martin G. Abbott, LLB
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

<i>Years ended December 31, 2004 and 2003 (\$ thousands, except per share amounts)</i>	<i>2004</i>	<i>2003*</i>
Revenue		
Production revenue <i>(note 3(e))</i>	108,103	73,282
Royalties, net of Alberta Royalty Tax Credit	(23,067)	(15,078)
	85,036	58,204
Other income	–	600
	85,036	58,804
Expenses		
Operating	20,019	15,075
Transportation costs <i>(note 3(e))</i>	1,879	1,110
General and administrative	3,797	3,196
Stock-based compensation <i>(note 3(d))</i>	446	445
Interest on long-term debt	2,141	2,401
Depletion, depreciation and accretion	30,269	20,780
	58,551	43,007
Earnings before taxes	26,485	15,797
Taxes <i>(note 7)</i>		
Future income taxes	9,543	480
Current	787	720
	10,330	1,200
Net earnings	16,155	14,597
Retained earnings, beginning of period	36,205	23,504
Retroactive application of change in accounting policy <i>(note 3)</i>	–	31
Acquisition of share in excess of assigned value <i>(note 6(f))</i>	(1,181)	(1,927)
Retained earnings, end of period	51,179	36,205
Basic earnings per share <i>(note 6(g))</i>	\$ 0.60	\$ 0.64
Diluted earnings per share <i>(note 6(g))</i>	\$ 0.58	\$ 0.63

* Restated (see note 3)

See accompanying notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

<i>Years ended December 31, 2004 and 2003 (\$ thousands)</i>	<i>2004</i>	<i>2003*</i>
Cash provided by (used in):		
Operating activities		
Net earnings	16,155	14,597
Items not involving cash		
Depletion, depreciation and accretion	30,269	20,780
Stock-based compensation	446	445
Future income taxes (note 7)	9,543	480
Abandonment expenditures	(240)	(160)
Cash flow from operations	56,173	36,142
Changes in non-cash working capital:		
Increase in trade and other receivables	(3,467)	(2,135)
Decrease (increase) in prepaid expenses	179	(250)
Increase in trade and other payables	3,122	2,971
	56,007	36,728
Financing activities		
Issue of common shares	47,337	15,345
Issue of share capital on exercise of stock options	1,089	1,359
Repurchase of shares (note 6(f))	(1,933)	(3,503)
Share issue costs	(3,156)	(942)
Increase (decrease) in long-term debt	(16,018)	8,603
	27,319	20,862
Investing activities		
Additions to capital assets	(90,620)	(59,603)
Proceeds on property dispositions	309	104
	(90,311)	(59,499)
Changes in non-cash working capital:		
Decrease (increase) in trade and other receivables	(2,291)	1,034
Increase in trade and other payables	9,276	875
	(83,326)	(57,590)
Change in cash	-	-
Cash, beginning of period	-	-
Cash, end of period	-	-
Supplementary disclosure		
Cash interest paid	2,099	2,234
Capital taxes paid	542	719

* Restated (see note 3)

See accompanying notes to Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2004 and 2003 (Tabular amounts in thousands of dollars, unless otherwise noted)

1. Nature of Business

Real Resources Inc. (Real or the Company) is a public company whose business is the exploration for and development of crude oil and natural gas in Western Canada. Real is incorporated under the Alberta Business Corporations Act and is listed on the Toronto Stock Exchange.

2. Accounting Policies

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada. The preparation of the Consolidated Financial Statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

(a) Principles of consolidation

The Consolidated Financial Statements include the accounts of the Company, its subsidiary and its partnership.

(b) Joint operations

Significant portions of the Company's oil and gas activities are conducted jointly with others and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

(c) Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for asset retirement obligations are based on estimates. The cost-recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(d) Property, plant and equipment (PP&E)

The Company follows the full-cost method of accounting for exploration and development expenditures. All costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre as all operations are in Canada. Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the PP&E are capitalized. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 percent or more.

(e) Depletion and depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production which is based on:

- (i) total estimated proved reserves calculated in accordance with National Instrument 51-101;
- (ii) total capitalized costs plus estimated future development costs of proved undeveloped reserves including future estimated asset retirement costs, less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced; and
- (iii) relative volumes of petroleum and natural gas reserves and production before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

(f) Impairment

The Company places a limit on the aggregate carrying value of PP&E.

Impairment is recognized if the carrying amount of the PP&E exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third-party quoted forward prices, adjusted for the Company's contract prices and quality differentials.

Upon recognition of impairment, the Company would then measure the amount of impairment by comparing the carrying amounts of the PP&E to the fair value of PP&E which is the estimated net present value of future cash flows from proved plus risked probable reserves. The Company's risk-free interest rate is used to arrive at the net present value of future cash flows. Any excess carrying value above the net present value of the Company's future cash flows would be recorded as a permanent impairment.

(g) Asset retirement obligation

The Company recognizes the fair value of its asset retirement obligation (ARO) in the period in which it is incurred and when a reasonable estimate of fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs.

(h) Derivative financial instruments

The Company may use various derivative financial instruments from time-to-time to manage its commodity price, foreign exchange and interest rate exposures. The Company does not use these instruments for trading purposes. The derivative financial instruments are initiated within the guidelines of the Company's risk management policy.

The Company hedges its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars when it is deemed appropriate. These derivative contracts are not accounted for as hedges under Accounting Guideline 13 and are recorded at fair value on the Company's Consolidated Balance Sheet, with changes in fair value recorded in earnings. Premiums paid or received are deferred and amortized to earnings over the term of the contract. The Company may also enter into foreign exchange forward contracts to hedge anticipated US dollar denominated petroleum and natural gas sales.

(i) Revenue recognition

Revenues from sales of petroleum and natural gas are recorded when title passes from the Company to external parties.

(j) Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any differences between the accounting and the income tax basis of an asset or liability using income tax rates substantively enacted at the Balance Sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

(k) Stock-based compensation plan

The Company's Option Plan provides for granting of stock options to directors, officers and employees. The Company uses the fair value method for valuing stock option grants. Compensation costs attributed to share options granted are measured at fair value at the grant date and expensed over the expected exercise time-frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(l) Per share information

Per share information is calculated on the basis of weighted average number of common shares outstanding during the fiscal year. Diluted per share information reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options would be used to buy back common shares at the average market price for the period.

(m) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. A future tax liability is recognized upon the renunciation of the tax pools and share capital is reduced by the estimated costs of the renounced tax deductions.

3. Changes in Accounting Policies

(a) Full cost accounting guideline

In January 2004, the Company adopted Accounting Guideline 16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants (CICA) which replaces Accounting Guideline 5 "Full Cost Accounting in the Oil & Gas Industry".

Under Accounting Guideline 5, future net revenues for ceiling test purposes were based on proved reserves and were not discounted. Estimated future general and administrative costs and financing charges associated with future net revenues were deducted in arriving at the "ceiling".

There were no charges to net income, property, plant and equipment or any other reported amounts in the Consolidated Financial Statements as a result of adopting this guideline.

(b) Asset retirement obligation

In January 2004, the Company adopted CICA Handbook Section 3110 "Asset Retirement Obligations". This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

Previously, the Company recognized a provision for site restoration and abandonment costs calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves and the estimated future liability.

As a result of this change, the Consolidated Financial Statements at January 1, 2004 were changed as follows: property, plant and equipment increased by \$6.9 million; asset retirement obligation liability increased by \$7.0 million; future income tax liability decreased by \$0.1 million and retained earnings remained unchanged.

See note 9 for additional information on the asset retirement obligation and the impact on the Consolidated Financial Statements.

(c) Hedging

In January 2004, the Company adopted Accounting Guideline 13 "Hedging Relationships." The guideline addresses the types of financial instruments that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness. Financial instruments that are not designated as hedges are recorded at fair value on the Company's Consolidated Balance Sheet, with changes in fair value recorded in earnings.

The Company has not designated its financial instruments as hedges under the guideline. For derivative financial instruments that did not qualify as hedges at transition, the financial instruments were recognized on the Balance Sheet at fair value resulting in a deferred charge being recognized. The deferred charge was recognized in earnings on the same basis as the original hedged item. Subsequently, any changes in the fair value of the derivative were recognized in earnings as they arose. Hedging activities are reported as part of production revenue.

As a result of adopting this guideline, Real recognized a deferred charge of \$0.9 million relating to the unamortized loss on the financial instruments held at December 31, 2003 and recognized a financial instrument liability of \$0.9 million at the same time. The Company has no financial instruments in place at December 31, 2004.

(d) Stock-based compensation plan

In January 2004, the Company adopted the amended CICA Handbook Section 3870 "Stock-based Compensation and Other Stock-based Payments." This change in accounting policy has been applied retroactively with restatement of prior periods presented.

Under this amended standard, the Company must account for compensation expense based on the fair value of rights granted under its stock-based compensation plan (see note 6(d)). Under this method, compensation costs attributable to share options granted to employees or directors are measured at fair value at the grant date and expensed over the expected exercise time-frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

Previously, the Company accounted for its stock-based compensation using the intrinsic value method. No compensation costs were recorded in the financial statements for stock options granted as the options had no intrinsic value at the date of grant. Consideration paid by employees on the exercise of stock options and purchase of stock was credited to share capital.

As a result of this change, the Consolidated Financial Statements at January 1, 2004 were changed as follows: contributed surplus increased by \$0.7 million and retained earnings decreased by \$0.7 million.

(e) Transportation costs

In accordance with section 1100 of the CICA handbook, transportation costs are no longer netted against oil and natural gas revenue, but are disclosed as a separate expense in the Consolidated Statement of Operations and Retained Earnings.

4. Property, Plant and Equipment

	2004	2003
Oil and gas property, plant and equipment	379,362	288,150
Other	1,109	815
	380,471	288,965
Less: accumulated depletion and depreciation	117,578	88,182
	262,893	200,783

At December 31, 2004, oil and gas properties included \$23.8 million (2003: \$16.8 million) relating to unproved properties which have been excluded from the depletion and depreciation calculation. Future development costs on proved undeveloped reserves of \$15.1 million (2003: \$16.4 million) are included in the depletion calculation.

Included in the Company's property, plant and equipment balance is \$7.1 million (\$6.9 million at December 31, 2003) net of accumulated depletion relating to the asset retirement obligation.

In 2004, the Company capitalized \$1.9 million (2003: \$1.2 million) of overhead directly related to exploration and development activities.

Real performs a ceiling test calculation at least annually in accordance with the Canadian Institute of Chartered Accountants' full cost accounting guidelines. No write-down was required for the year ended December 31, 2004 based on expected future commodity prices of \$39.38 per barrel for crude oil and \$6.39 per mcf for natural gas. No write-down was required for the year ended December 31, 2003 based on year-end commodity prices of \$40.92 per barrel for crude oil and \$6.08 per mcf for natural gas.

5. Long-Term Debt

At December 31, 2004, the Company had a \$95 million financing commitment with a Canadian chartered bank which provided for an extendible revolving term credit facility and a US \$15 million swap facility. The credit facility revolves and fluctuates at the Company's option for a maximum of 364 days after the date of the bank's consent. If the revolving facility is not renewed at the end of the current revolving phase, the facility moves into the term phase whereby the credit facility will be permanently reduced by one payment on the 366th day following the last day of the revolving phase, which is the maturity date, in an amount equal to the outstanding principal.

The credit facility provides that advances may be made by way of direct advances, bankers' acceptances or US dollar LIBOR advances which bear interest at prevailing bankers' acceptances or LIBOR rates plus an applicable bank fee per annum or bank's prime lending rate, depending on the nature of the advance. The authorized limit is subject to an annual review and re-determination of the Company's borrowing base by the bank.

Collateral pledged for the facility consists of a fixed and floating charge demand-debenture in the principal amount of \$150 million conveying a floating charge on all of the property and assets of the Company.

6. Share Capital

(a) Authorized

Unlimited number of voting common shares without par value.

Unlimited number of first, second, third and fourth class preferred shares, issuable in series.

(b) Common shares issued

	2004		2003	
	Number of Shares (thousands)	Amount (\$ thousands)	Number of Shares (thousands)	Amount (\$ thousands)
Balance at beginning of year	23,351	52,693	20,507	38,120
Issue of common shares (c)	4,305	27,337	3,100	15,345
Flow-through share issue (d)	1,270	20,000	—	—
Future tax on flow-through issue (d)	—	(6,786)	—	—
Adjustment to holdback on corporate acquisition	—	—	(7)	(34)
Issued for cash on exercise of stock options	439	1,089	495	1,359
Repurchase of common shares (g)	(275)	(752)	(744)	(1,576)
Stock-based compensation (note 3(d))	—	80	—	35
Share issue costs (net of tax effect)	—	(1,894)	—	(556)
Balance at end of year	29,090	91,767	23,351	52,693

(c) On March 30, 2004, the Company closed a common share equity offering for a total of 4.305 million common shares at a price of \$6.35 per share for total gross proceeds of \$27.3 million (\$25.6 million net of expenses).

On March 21, 2003, the Company closed a common share equity offering for a total of 3.1 million common shares at a price of \$4.95 per share for total gross proceeds of \$15.3 million (\$14.4 million net of expenses).

(d) On December 16, 2004, the Company closed a flow-through share equity offering for a total of 1.27 million common shares at a price of \$15.75 per share for total gross proceeds of \$20.0 million (\$18.7 million net of expenses). Real committed to spending \$20.0 million in qualifying Canadian Exploration Expenditures pursuant to this flow-through share issue in December 2004. All of the expenditures were renounced effective December 31, 2004 with the expenditures to be incurred prior to December 31, 2005.

(e) Stock-based compensation plan

The Company has a stock option plan that provides for the issuance of options to its directors, officers and employees to acquire up to 1.932 million common shares. The options typically vest evenly over a three-year period and expire five years from the date of grant. Compensation costs attributable to share options granted to employees or directors are measured at fair value at the grant date and expensed over the expected exercise time-frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The stock-based compensation expense does not include compensation costs associated with stock options granted prior to January 1, 2002. The fair value of each option granted is estimated on the date of grant using the Black-Scholes options pricing model with the following weighted average assumptions:

	2004	2003
Fair value of options granted (\$/share)	1.46	0.95
Risk-free interest rate (%)	2.9	3.5
Expected life (years)	3.3	3.5
Expected volatility (%)	29	28
Expected dividend yield (%)	—	—

Stock option plan

A summary of the status of the Company's stock option plan as of December 31, 2004 and 2003, and changes during the years ended on those dates is presented below:

	2004		2003	
	Number of Options (thousands)	Weighted Average Exercise Price (\$/share)	Number of Options (thousands)	Weighted Average Exercise Price (\$/share)
Balance, beginning of year	1,942	3.77	1,786	3.14
Granted	475	7.11	793	4.61
Exercised	(439)	2.48	(495)	2.75
Expired/cancelled	(46)	5.23	(142)	4.12
Balance, end of year	1,932	4.85	1,942	3.77
Exercisable at end of year	845	3.90	777	2.88

The following table summarizes information regarding stock options outstanding at December 31, 2004:

Range of Exercise Prices	Options Outstanding at December 31, 2004			Options Exercisable at December 31, 2004	
	Number Outstanding (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (\$/share)	Number Exercisable (thousands)	Weighted Average Exercise Price (\$/share)
\$1.92 – \$3.52	445	1.4	3.31	398	3.31
\$3.70 – \$4.35	236	2.6	3.99	139	3.94
\$4.45 – \$4.50	473	3.5	4.46	158	4.46
\$4.60 – \$5.78	385	3.5	4.99	150	4.87
\$6.98 – \$9.45	393	4.5	7.44	—	—
	1,932	3.1	4.85	845	3.90

(f) Normal Course Issuer Bid

On June 17, 2004 (June 17, 2003) the Company announced its intention to make a Normal Course Issuer Bid (the "Bid") through the facilities of the Toronto Stock Exchange to acquire for cancellation up to 1,391,000 common shares of the Company (June 17, 2003 Bid: 1,173,400 common shares), which represented approximately five percent of the Company's issued and outstanding common shares. The Bid commenced on June 21, 2004 (June 19, 2003) and will terminate on June 20, 2005 (June 18, 2004). The Company purchased 55,100 common shares under this Bid (June 17 2003 Bid: 449,600 common shares) for a total cost of \$450,000 (June 17 2003 Bid: \$2.5 million). The excess cost over book value of the shares purchased was applied to Retained Earnings.

(g) Per share amounts

The following table summarizes the basis for determining the basic and diluted per share amounts:

	2004	2003
Weighted average shares outstanding <i>(thousands)</i>	26,932	22,804
Dilutive stock options outstanding <i>(thousands)</i>	1,917	1,783
Shares repurchased with proceeds from dilutive stock options and returned to treasury <i>(thousands)</i>	(1,125)	(1,361)
Weighted average diluted common shares outstanding <i>(thousands)</i>	27,724	23,226
Net earnings per common share		
Net earnings	16,155	14,597
Basic <i>(\$/share)</i>	0.60	0.64
Diluted <i>(\$/share)</i>	0.58	0.63

During 2004, 15,000 stock options were anti-dilutive and were omitted from the weighted average diluted common shares outstanding calculation (2003: 159,000).

7. Taxes

The difference between the expected income tax provision based on the combined federal and provincial statutory tax rate of 39.3 percent (2003: 40.9 percent) and the amount actually provided for is as follows:

	2004	2003
Expected future income taxes	10,382	6,658
Non-deductible Crown payment	4,801	4,129
Alberta Royalty Tax Credit	(125)	(153)
Resource allowance	(4,200)	(3,258)
Rate reduction	(791)	(7,004)
Change due to timing of future revenue estimates	(727)	–
Other	203	108
Total future income taxes	9,543	480
Capital taxes	787	720
Total taxes	10,330	1,200

The Company's future income tax liability as at December 31, 2004 is comprised of the following:

	2004	2003
Property, plant and equipment having different income tax and accounting basis	52,450	35,782
Asset Retirement Obligation	(4,615)	(3,764)
Share issuance costs	(1,069)	(319)
	46,766	31,699

8. Commitments

Real is committed to payments under operating leases for office space, gathering and transportation obligations, equipment leases and vehicles as follows:

2005	725
2006	604
2007	406
2008	381
2009	63
Thereafter	—
	2,179

9. Asset Retirement Obligation

The total future asset retirement obligation was estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its total asset retirement obligations to be \$13.6 million at December 31, 2004 based on a total future liability of \$25.9 million. These payments are expected to be made over the next 21 years with the majority of costs incurred between 2014 and 2018. The Company's credit adjusted risk-free rate of seven percent and an inflation rate of two percent were used to calculate the net present value of the asset retirement obligation.

The following table reconciles the Company's total asset retirement obligation:

	2004	2003
Balance at January 1 <i>(restated – see note 3)</i>	11,807	10,117
Increase in liabilities	1,195	1,112
Settlement of liabilities	(240)	(160)
Accretion expense	873	738
Balance at December 31	13,635	11,807

10. Contributed Surplus

The following table reconciles the Company's contributed surplus:

	2004	2003
Balance at January 1 <i>(restated – see note 3)</i>	682	271
Stock-based compensation expense	446	445
Options exercised	(80)	(34)
Balance at December 31	1,048	682

11. Financial Instruments

The Company's financial instruments recognized in the Consolidated Balance Sheets consist of accounts receivable, accrued liabilities and long-term debt.

The carrying value of accounts receivable, accounts payable and accrued liabilities and long-term debt approximate their fair market value.

A substantial portion of the Company's accounts receivable are with customers and joint-venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's oil, gas and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

12. Subsequent Event

On February 10, 2005, the Company announced a common share equity offering for a total of 2.527 million common shares at a share price of \$13.85 for total gross proceeds of \$35.0 million. This offering closed on March 1, 2005. Proceeds from the offering will be used to fund the Company's ongoing exploration and development activities and for general corporate purposes.

WHO IS CONTRIBUTING TO REAL'S PERFORMANCE?

Real's strength lies in the quality of our dedicated staff. Their commitment, enthusiasm and expertise are the foundations of the Company's future growth.



Caryn Allen
Leah Aispach
Greg Anderson
Cathy Anton
Renee Arseneau
Randy Bartlett
Kathy Bonham-Curtis
Jane Brezinski
Veda Burby
Terry Butterworth
Rhonda Chalmers
Samantha Chan
Tom Charuk
Dale Collette
Robert Conrad
Silvana Corradetti
Dale Cugnet
Clay Curry
Edward Cutts
Lee Davis
Sandy Denton
Connie Edlund
Jonny Evenson
Colin Flanagan
Wade Golby
Miriam Goodman
Larry Green
Dolores Grzelak
Dale Hoff
Lowell Jackson
Kevin Kelts
Mike Kolenosky
Bob Lagimodiere
Monty Low
Chris Madsen
Stephen Marston
Muriel McCallum
Valerie Morrison
Frank Muller
Ken Murphy
Mary Murphy-Watch
Lyle Nakaska
Pamela Orr
Steve Parkins
Jennifer Perry
Dan Petch
Lori Peters
Tara Proctor
Joe Recksky
Bob Riopel
Daryll Robinson
Tammy Rochon
Kevin Roll
Michael Scase
Jennifer Scharnau
Michael Slezak
Brian Sondergaard
Geri Spring
Michael Stone
Roy Taylor
April Toth
Kahlil Trotman
Dean Tucker
Jim Twanow
Lisa Ulseth
Erik Vik
Larry Ward
Veera Wiber
Rodi Wiest
Zofia Wojcicka

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D. Nolan Blades, P.Eng. ^(2,3)
Frans Burger ^(1,3,5)
Dallas L. Droppo, Q.C. ⁽⁵⁾
Lowell E. Jackson, P.Eng. ^(4,5)
Robert B. Michaleski, CA ⁽¹⁾

Committees

Audit Committee ⁽¹⁾
Compensation Committee ⁽²⁾
Reserve Audit Committee ⁽³⁾
Environmental, Health & Safety Committee ⁽⁴⁾
Risk Management Committee ⁽⁵⁾

Officers

Lowell E. Jackson, P.Eng.
President & Chief Executive Officer

Ken P. Murphy, P.Land
Executive Vice President

Pamela J. Orr, CA, CFA
Vice President Finance
& Chief Financial Officer

Frank P. Muller, P.Geol.
Vice President Exploration

Dallas L. Droppo, Q.C.
Secretary

Legal Counsel

Blake, Cassels & Graydon LLP
Calgary, Alberta

Banker

Canadian Imperial Bank of Commerce
Calgary, Alberta

Registrar and Transfer Agent

Computershare Investor Services Inc.
Calgary, Alberta

Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Reserve Consultants

Paddock, Lindstrom & Associates Ltd.
Calgary, Alberta

Stock Exchange

Toronto Stock Exchange
Trading Symbol: RER

Annual General and Special Meeting

Shareholders are cordially invited to attend the Annual General and Special Meeting of Real Resources Inc., which will be held on May 5, 2005 at the Selkirk Conference Centre on the second floor at 555 - 4th Avenue SW, Calgary, Alberta at 3:00 pm.

If unable to attend, shareholders are requested to complete and return the Proxy form to the Secretary of the Company.

ABBREVIATIONS

bbls	barrels
mbbls	thousands of barrels
bbls/d	barrels of oil per day
mcf	thousand of cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
boe	barrel of oil equivalent where natural gas is equated to oil using 6 mcf = 1 barrel of oil
mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
NGL	natural gas liquids

TRADING SUMMARY

2004	Price Range (\$)			Trading Volume
	High	Low	Close	
1st Quarter	6.62	5.33	6.35	6,249,258
2nd Quarter	8.95	6.26	7.45	6,041,930
3rd Quarter	9.60	7.25	9.45	4,355,991
4th Quarter	13.55	9.30	11.84	9,553,409
				26,200,588



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